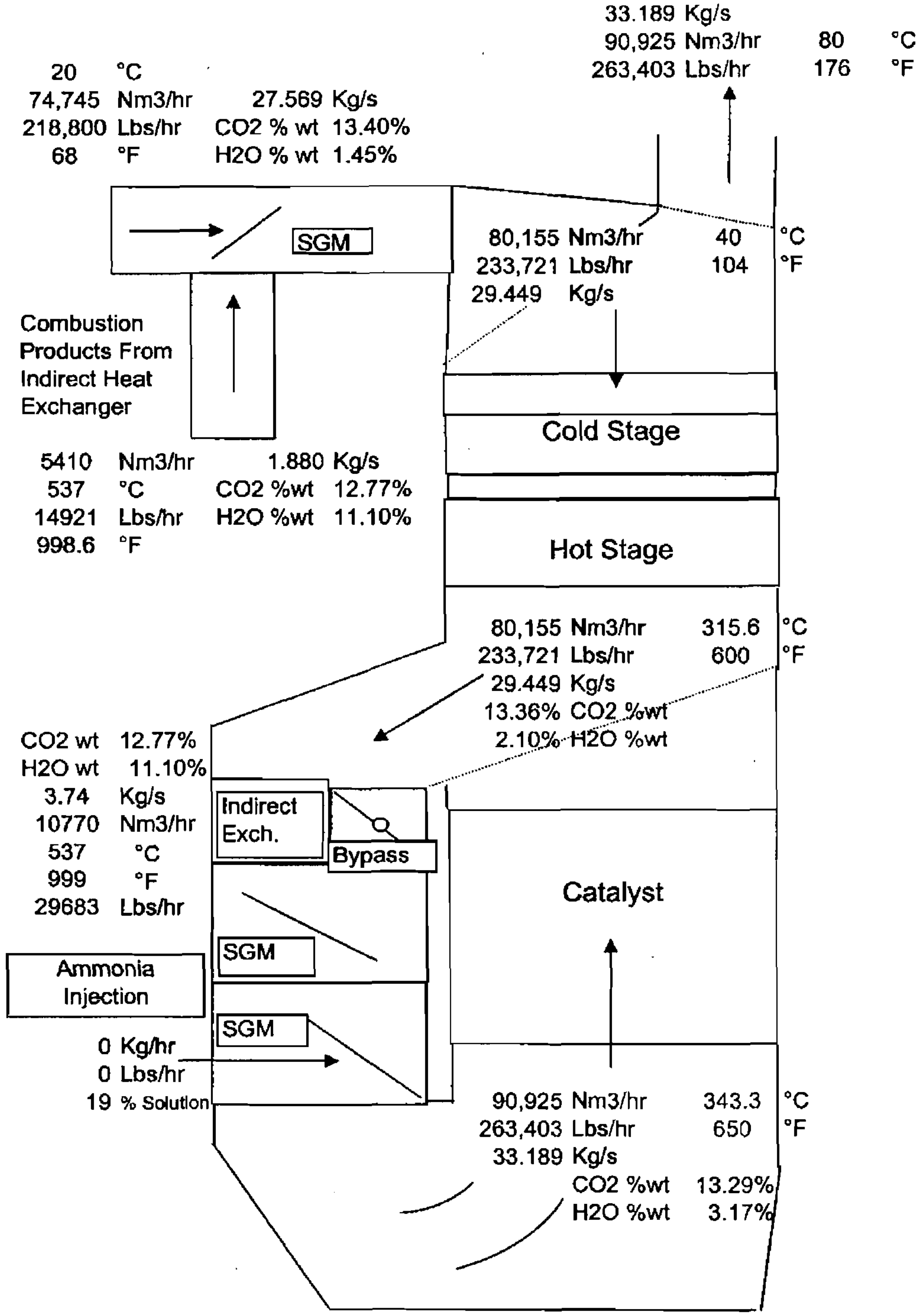
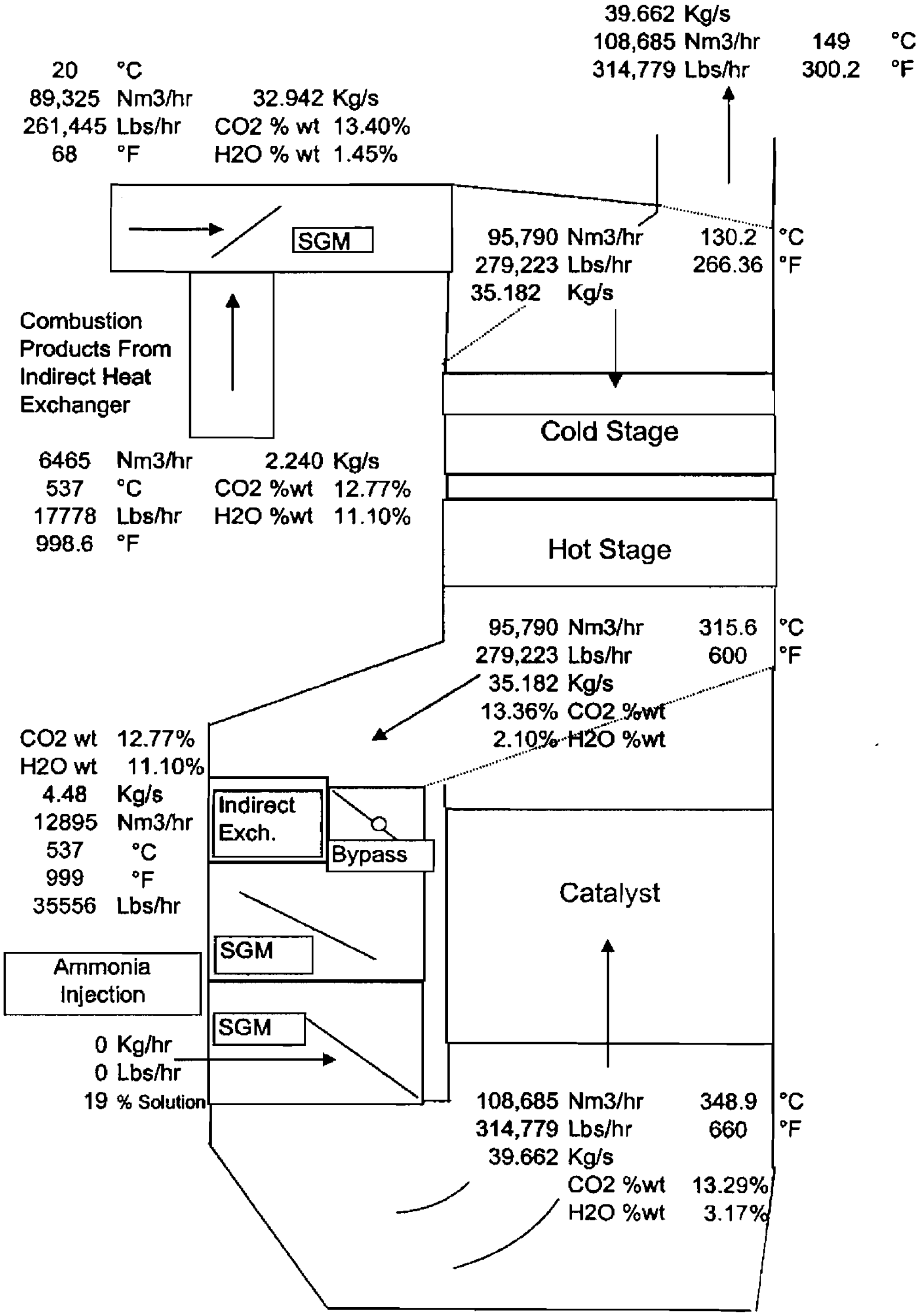
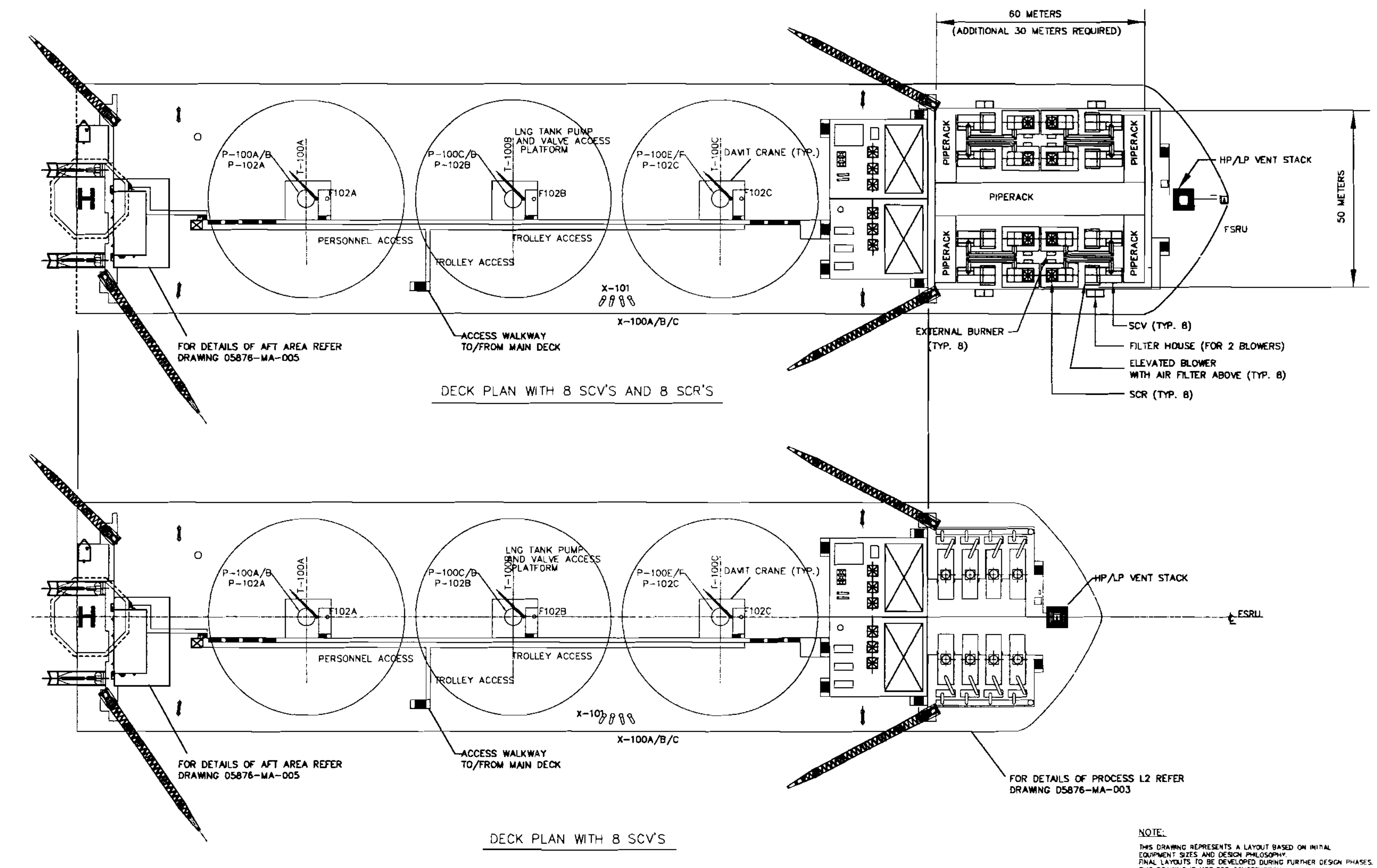
Remote Direct Fired Heater - Normal Operation



Remote Direct Fired Heater - Maximum Flow





NOTE:

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THIS DRAWING IS NOT FOR CONSTRUCTION.

NO.	DESCRIPTION	DATE	APPR.

REVISIONS

	BY	DATE
DRAWN	CHAMPION	12/01/06
CHKD.		
APPR.		
APPR.		

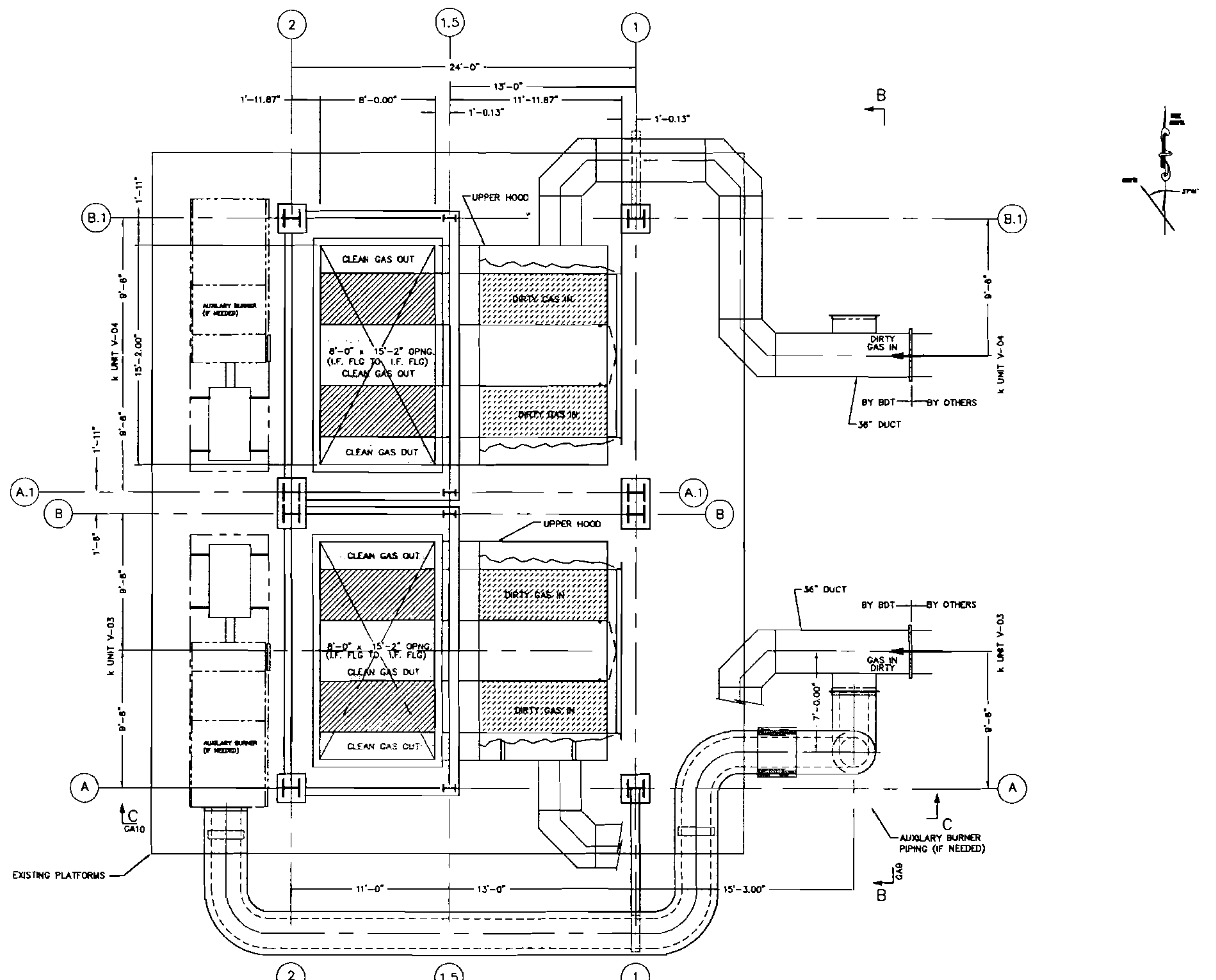
SCALE: 1:500

AKER KVÆRNER
Houston, Texas

OVERALL PLAN COMPARISON
8 SCV's/8 SCR's vs. 8 SCVs/0 SCR's
CABRELLO PORT FSRU

FOR: CABRELLO PORT TERMINAL

CONTRACT NO.	DRAWING NO.	REV.
H0690900	PIP-2006-002	A



PLAN VIEW
SCALE: 1/4" = 1'-0"

PRELIMINARY DRAWING
FOR INFORMATION ONLY

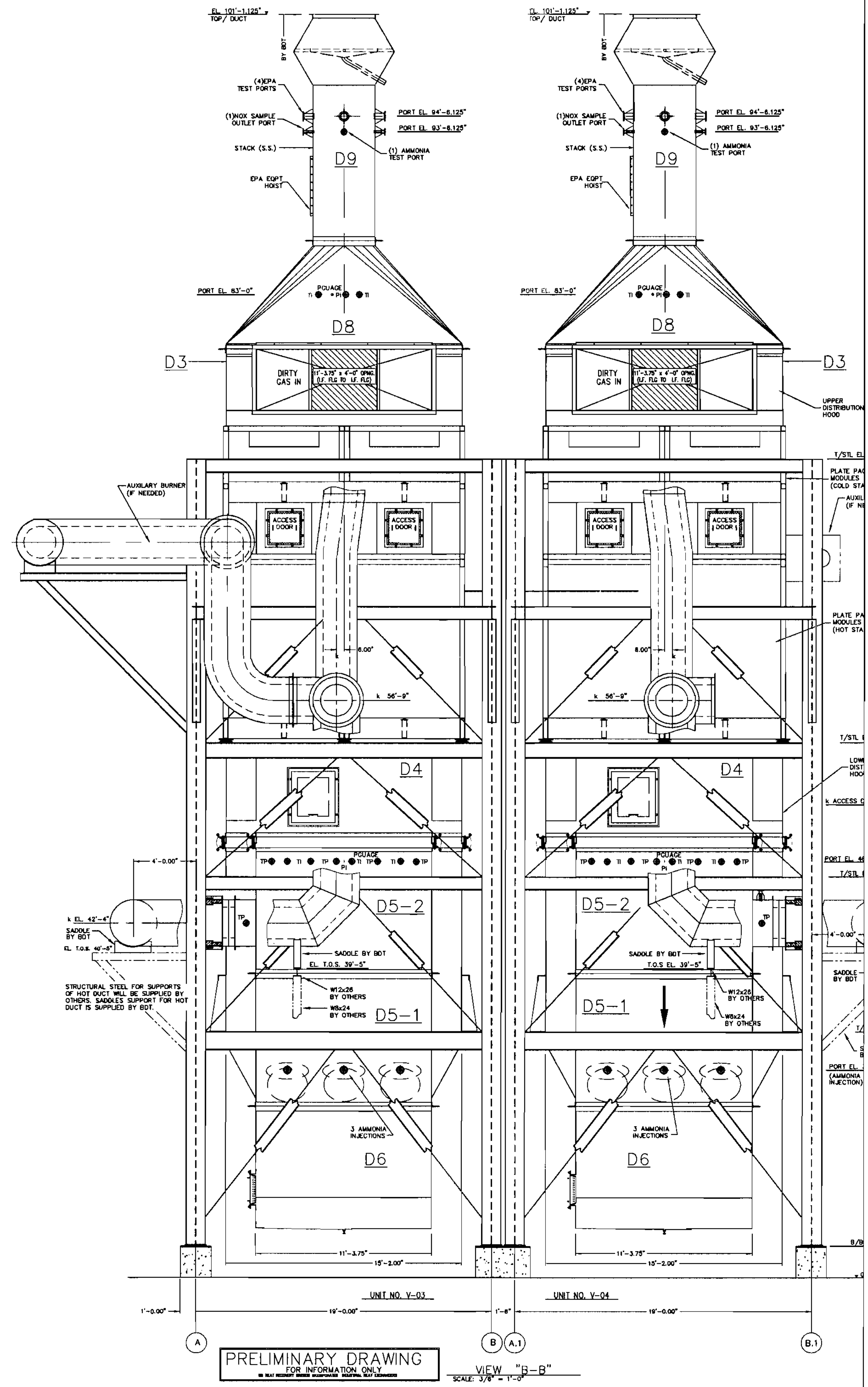
NO.	DATE	BY	APPD.	REVISION	NO.	DATE	BY	APPD.	REVISION	ISSUED FOR	DATE	BY	ISSUED FOR	DATE	BY
													PROPOSAL		JAC

COMPACT DeNOx SYSTEM
WORLEY PARSONS
MELBOURNE, AUSTRALIA
JOB NO.: 351/05876

BE HEAT RECOVERY DIV., INC# 05-1008

BD HEAT RECOVERY DIV., INC

DRAWING TITLE	PROPOSED GENERAL ARRANGEMENTS PLAN VIEW		
DRAWN: JAP	DATE: 04/22/05	REV.	DWG. NO.
CHECKED: DT	DATE: 04/22/05	A	PGA1
APPRVD: JAC	DATE: 04/22/05		
SCALE: AS NOTED	DWG.SIZE: 24X36		



PRELIMINARY DRAWING
FOR INFORMATION ONLY

VIEW "B-B"
SCALE: 3/8" = 1'-0"

(D1 & D2 NOT SHOWN FOR CLARITY)

NO.	DATE	BY	APPD.	REVISION

ISSUED FOR	DATE	BY
PROPOSAL		JAC

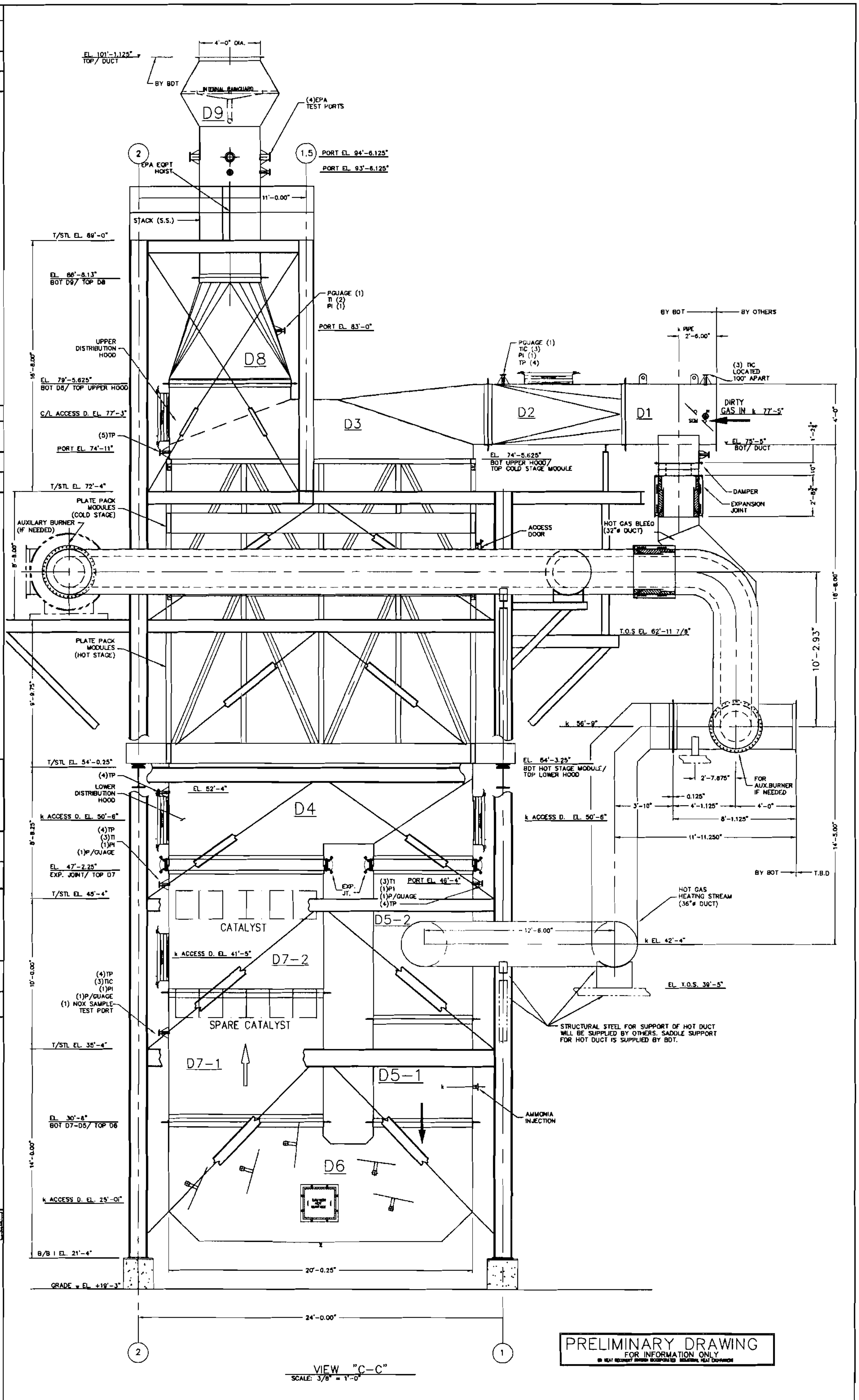
COMPACT DeNOx SYSTEM
WORLEY PARSONS
MELBOURNE, AUSTRALIA
JOB NO.: 351/05876

BE HEAT RECOVERY DIV., INC# 05-1008

BD HEAT RECOVERY DIV., INC

DRAWING TITLE: PROPOSED GENERAL ARRANGEMENTS VIEW "B-B"

DRAWN: JAP DATE: 04/22/05
CHECKED: DT DATE: 04/22/05
APPROVED: JAC DATE: 04/22/05
SCALE: AS NOTED DWG. SIZE: 24X36
REV. A
DWG. NO. PGA2



NO.	DATE	BY	APPD.	REVISION

ISSUED FOR	DATE	BY
PROPOSAL		JAC

COMPACT DeNOx SYSTEM
WORLEY PARSONS
MELBOURNE, AUSTRALIA
JOB NO.: 351/058 76

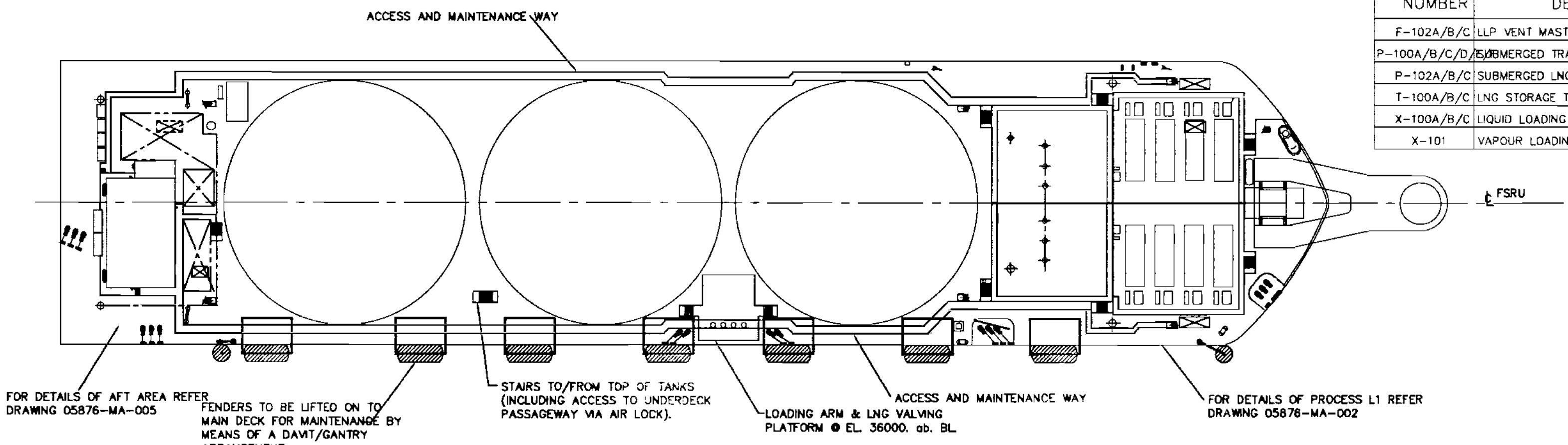
BE HEAT RECOVERY DIV., INC# 05-1008

BD HEAT RECOVERY DIV., INC

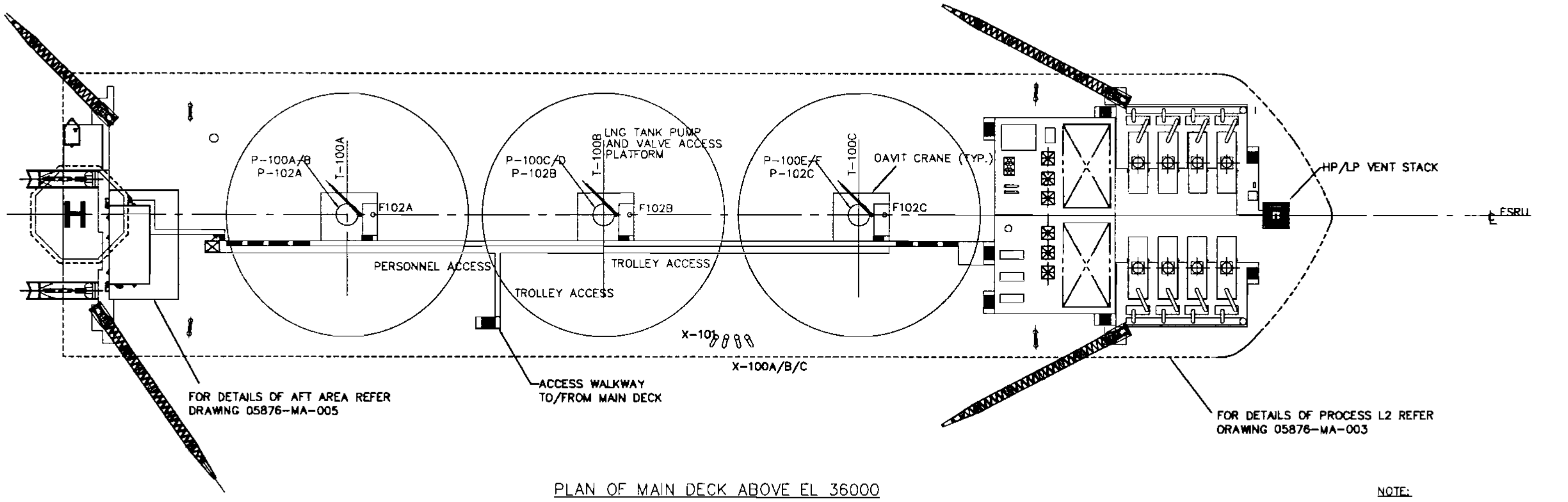
DRAWING TITLE: PROPOSED GENERAL ARRANGEMENTS VIEW "C-C"

DRAWN: JAP DATE: 04/22/05
CHECKED: DT DATE: 04/22/05
APPRVD: JAC DATE: 04/22/05
SCALE: AS NOTED DWG SIZE: 24X36
REV. A
DWG NO. PGA3

EQUIPMENT NUMBER	EQUIPMENT DESCRIPTION
F-102A/B/C	LLP VENT MAST
P-100A/B/C/D/E/F	SUBMERGED TRANSFER PUMP
P-102A/B/C	SUBMERGED LNG RECYCLE PUMP
T-100A/B/C	LNG STORAGE TANK
X-100A/B/C	LIQUID LOADING ARM
X-101	VAPOUR LOADING LINE



PLAN @ MAIN DECK EL 31000. AND PROCESS DECK LEVEL1 EL 36000.



PLAN OF MAIN DECK ABOVE EL 36000

NOTE:

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Worley

10 0 10 20 30 40 50
SCALE OF METRES 1:500

THIRD ANGLE PROJECTION UNLESS OTHERWISE NOTED

NOTES:

REV.	STATUS	DATE	REVISION DESCRIPTION	AUTHOR	CHECKED	DESIGN ENGINEER	RESP. ENGINEER	PROJECT MANAGER	EIS MANAGER
B	BR	03/04	ISSUED FOR FINAL REPORT						
A	BR	02/04	ISSUED FOR CLIENT REVIEW	MV	DS			LJW	

DRAWING No	DRAWING TITLE
REFERENCE DRAWINGS	

BHPB DRG No: WCLNG-BHP-PRO-RD-00-050

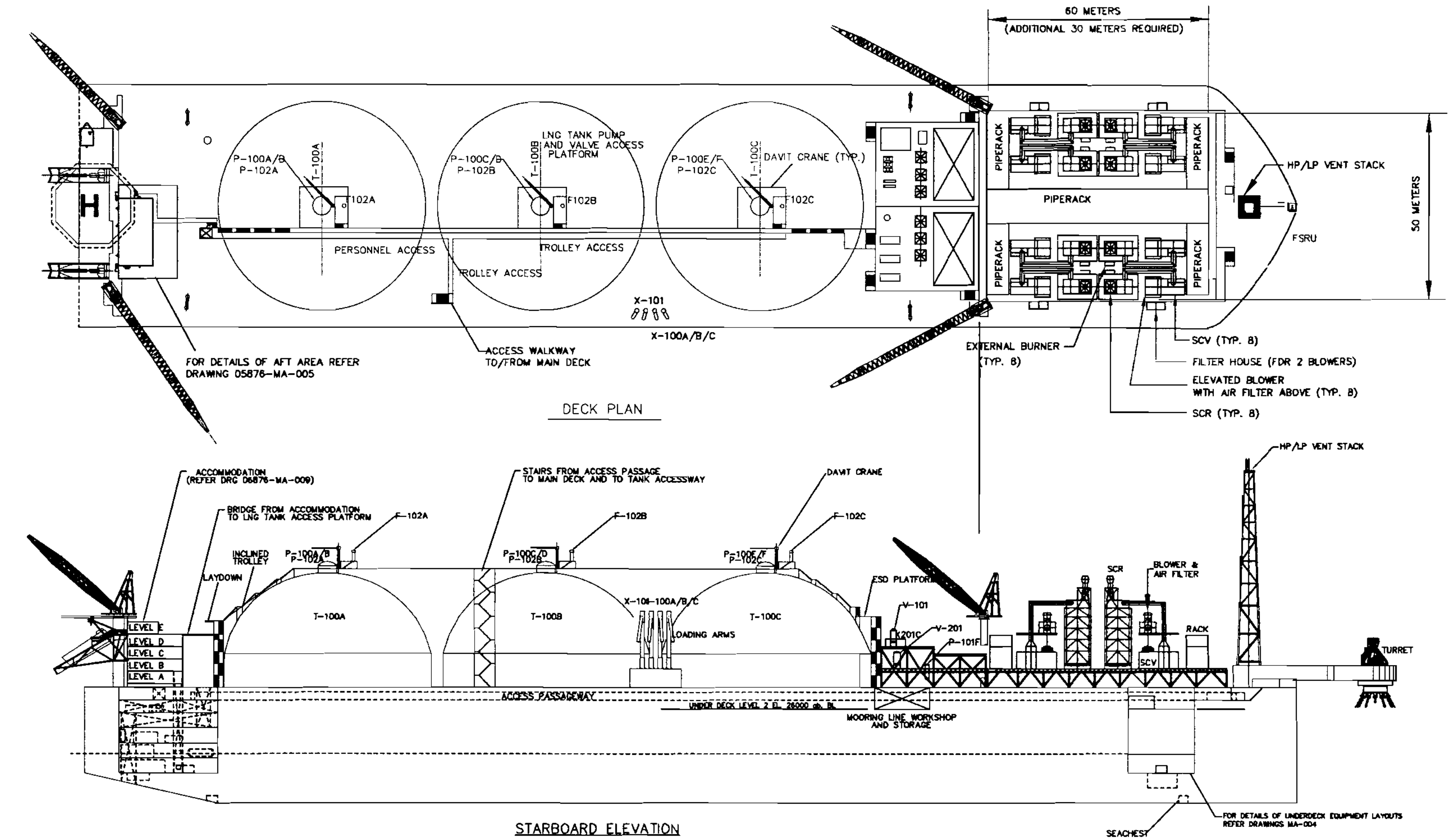
bhpbilliton BHP Petroleum

DOCUMENT CLASS: K1

TITLE: CABRILLO PORT FSRU MAIN DECK OVERALL LAYOUT

SCALE	PROJECT No	DRAWING No	REV.
1:500	35105876	05876-MA-001	

A1 AUTOCAD



NOTE:

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SCALE OF METRES 1:500

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	REVISIONS			DRAWN	CHAMPION	12/01/06
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				APPR.		
				APPR.		
				SCALE: 1:500		

AKER KVÆRNER
Houston, Texas

OVERALL PLAN AND ELEVATION
WITH 8 SCV's & 8 VERT. SCR's
CABRELLO PORT FSRU

FOR: CABRELLO PORT TERMINAL

CONTRACT NO.	DRAWING NO.	REV.
H0690900	PIP-2006-001	A

Discussions with Distrigas November 30, 2006

Distrigas representative – Jonathan R. Lauck, Engineering Manager
AK representative – Kamal Shah, John Siffert

Subject: Distrigas SCV unit.

Various issues as discussed are noted below:

- They still experience sodium carbonate carry over from the SCV bath reducing the life of catalyst. The changes in past to the SCV water bath pH neutralization system has helped reduce the salt carry over, but they still have salt carry over problems from the SCV water bath due to unknown reasons. They are continuing their research in finding where and how the salt is migrating from the SCV water bath to the catalyst bed. The current SCV unit catalyst life is less than 1 year increasing the operating cost.
- Distrigas does not utilize ammonia for pH adjustment in the SCV water bath.
- Distrigas does not have any CO catalyst bed.

Title

Operating Experiences with an Integrated Selective Catalytic Reduction System (SCR) Operating with Submerged Combustion Vaporizers (SCV) at a North American Base Load LNG Vaporization Facility

Author
David Hawkins – BD Heat Recovery Division, Inc.

Background

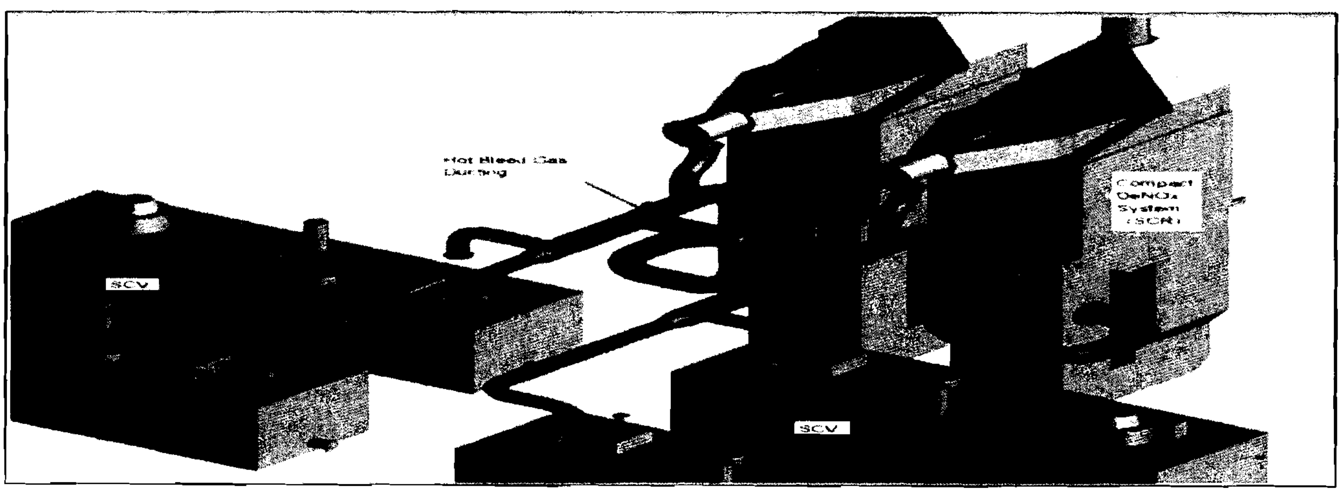
Since 2002 – and continuously since early 2003 a base load LNG vaporization facility has been operating with an integrated system comprised of four submerged combustion vaporizers (SCV) and two selective catalytic reduction systems (SCR). The system is configured with two SCV's operating with one SCR. This paper presents the system layout and the design considerations that resulted in the finalized design. In addition, the paper discusses some of the operating issues and remedial actions taken to resolve these issues.

System Configuration

One of the challenges of installing a SCR system to operate with a SCV is the low temperature and saturated condition of the flue gases leaving the vaporizer. SCR systems inject ammonia into the dirty gas stream; this mixture is then converted by catalytic action into nitrogen (N_2) and water (H_2O). In order to carry out the conversion the flue gases must be at a certain reactive temperature. This temperature can vary depending on a number of factors such as, catalyst type, selected volume, pressure drop and formation of ammonia salts. Temperatures are usually greater the 350°F and frequently in excess of 600°F. SCV's are a highly efficient form of vaporization and the outlet flue gas temperature is normally between 60°F to 120°F with the normal operating temperature around the 60°F level.

Additional heat is therefore required to elevate the flue gases to the reactive temperature. In the case of the facility discussed in this paper, the external heat was taken from the vaporizer prior to the exhaust gases passing through the water bath. The integrated system is shown in diagram 1.

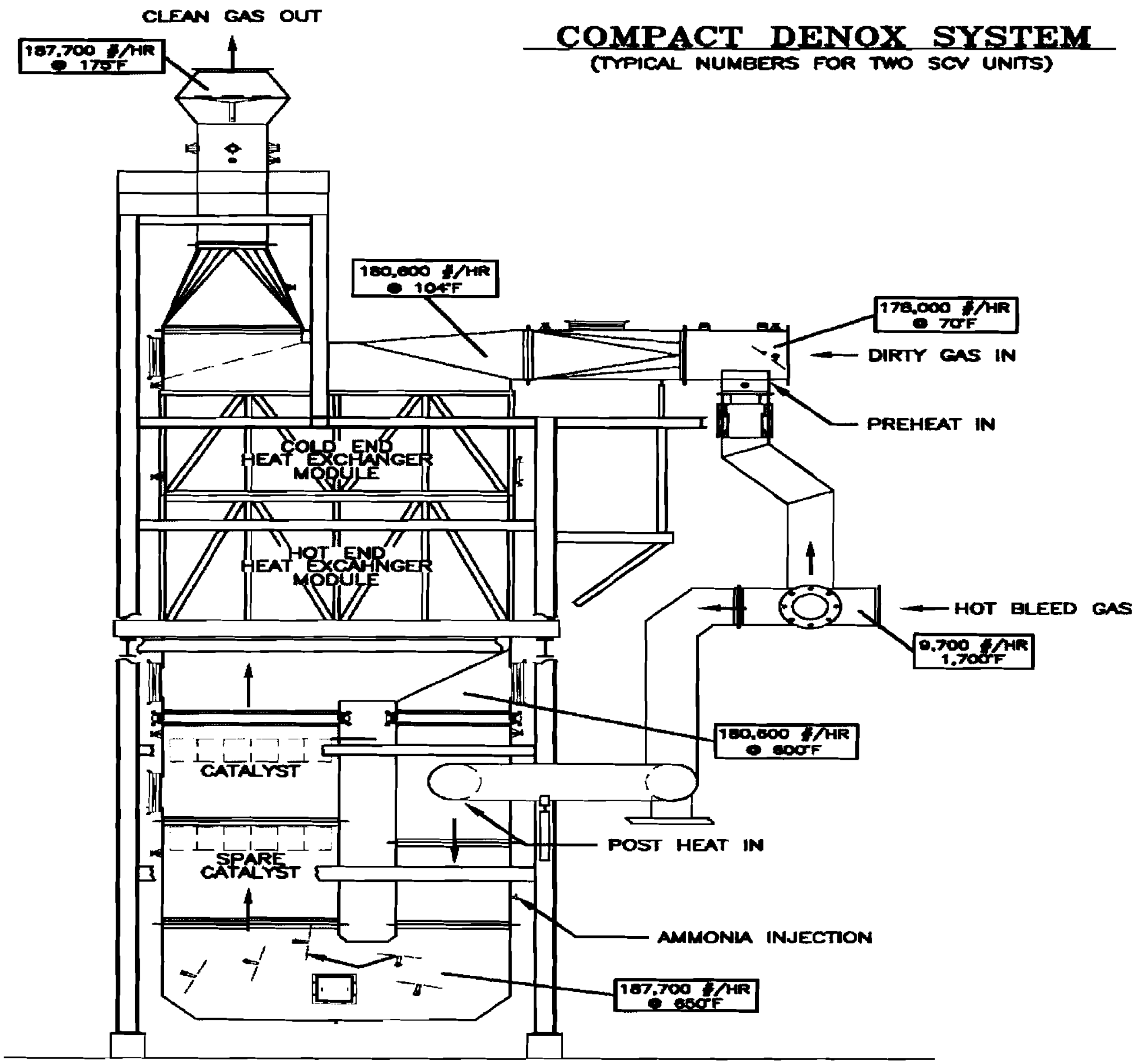
Diagram 1



The cool saturated flue gases exit from two vaporizers and are individually ducted to a common plenum prior to entering the single SCR. Hot bleed gases taken from beneath the water bath at approximately 1,700°F pass through a water-cooled control valve (located in the SCV water bath) prior to being ducted to the SCR system. The SCR system can operate with both SCV's or just a single SCV, even at reduced loads.

Prior to entering the SCR, the hot bleed gases are separated supplying heat to two locations. These locations are identified as the preheater and post-heater sections. A detailed schematic (diagram 2) shows the layout of the SCR system, which is termed by our company as "The Compact DeNOx System."

Diagram 2



To prevent the acidic saturated flue gases (ph ~ 6) from entering the cold stage of the heat exchanger, hot bleed gas is mixed (utilizing a static gas mixer) with the exhaust gases adding approximately 30°F to the cold gases.

Even though the cold section of the heat exchanger is manufactured from stainless steel 304, avoiding water droplets increases the life expectancy. The flue gases are heated in the cold stage of the heat exchanger to approximately 225°F prior to entering the hot stage (manufactured from carbon steel) where the gases are raised to 600°F. The flue gases are further heated to 650°F with the addition of 1,700°F hot bleed gas. Aqueous ammonia (19%) is then directly injected into the dirty flue gas stream. A static gas mixer incorporated into the duct produces a vortex, which provides thorough mixing. Additional static gas mixers are used throughout the system to distribute the ammonia, NOx, and temperature evenly across the catalyst face.

The hot gases are then ducted 180 degrees before passing up through a single layer of catalyst where the NOx is converted into Nitrogen (N_2) and water (H_2O). A spare catalyst layer is designed into the system so that additional catalyst can be added in the future as the reactivity of the original catalyst declines.

After passing through the Catalyst, the hot gases provide the heat source (via the heat exchanger) for heating the cold gases that initially entered the system. Finally the clean gases exit the system and are dispersed into the atmosphere with a maximum of 5-ppm NOx and 5-ppm ammonia slip.

Design Considerations

Heating System

Five methods of supplying the required heat input to the SCR system were considered

- Steam Coils
- Direct Gas Fired Burner Installed in the Pre and Post Heating Locations
- Indirect Gas Fired Air Heater
- Direct Gas Fired Air heater
- Hot Bleed Gases taken from the Submerged Combustion Vaporizer

Steam Coils

Due to the location of the steam plant plus pressure and temperature restrictions this option was not viable.

Gas Fired Burner

This option is employed on about 90% of our Compact DeNOx Systems installed in the USA and Europe. However, this option was considered unsuitable for the LNG application because the potential exists of a gas leak occurring in the SCV. This firing method would result in direct flame contact to the leaking methane.

Indirect Gas Fired Air Heater

With this option a separate gas fired air heater would be installed. A burner would supply heat to a refractory lined furnace. A separate air blower would supply air to tubes installed in the furnace; the hot air would then be piped to the pre and post heating locations in the system. This option was rejected because of cost and the addition of a second emission source.

Direct Fired Air Heater

This option uses a separate but direct gas fired Air Heater. The combustion point would be located at a significant distance from the pre and post heating locations. A blower would supply air over the gas-fired burner. The resulting hot air would pass to the pre and post heating locations at a higher pressure than present in the SCR system. Consequently, the potential for any direct flame contact with leaking gas was considered negligible. In addition, the combustion gases pass through the DeNOx system eliminating a secondary emission source. This option was built into the design as a back up to the chosen hot bleed gas system.

Hot Bleed Gas

The SCV supplier first suggested this option, which was chosen as the preferred heating system. A small portion of the gases generated by the large single burner (100 mm Btu/hr) would be extracted prior to the water bath. Based on the extraction point it was anticipated, that the flue gases would be approximately 1,700°F. At close to 99%, the SCV is an inherently efficient method of vaporization. Therefore, extracting flue gases prior to the water bath has an effect on the overall system efficiency. However, it was determined both from an operational and capital cost basis, this was the most cost effective choice. Unfortunately, this type of system had never previously been installed; therefore a backup system was part of the original design.

Once the bleed gas option was selected, the main considerations became the inter-connecting ducting between the SCV and the SCR and the use of high temperature control valves. To reduce the maintenance and improve reliability, water-cooled control valves were selected and located in the water bath of the SCV.

For the hot bleed gas ducting, the following insulation options were considered.

Refractory Lined Ducts – There were concerns that if the refractory degraded plugging of the heat exchanger and catalyst could occur.

Externally Insulated Ducts – The metallurgy required at 1,700°F was expensive and expansion issues could have been problematic.

Internally insulated Ceramic Fiber Lined Stainless Steel Ducts – This was the preferred option. Stainless steel 304 was used to avoid corrosion problems, should condensation occur between the duct wall and the internal insulation. Ceramic fiber insulation has been used for a number of years in steam reformers and was considered to be reliable. A ceramic fiber hard core was installed to prevent the soft fibers from being eroded.

Heat Exchanger

The counter-flow heat exchanger is a welded plate type manufactured to provide zero leakage and consequently no crossover contamination from the dirty to the clean side. The counter-flow design is essential to reduce the exchanger size and permit small gas-to-gas approach temperatures of 50°F or less which, results in a more efficient system. The installed heat exchanger was designed as a two-stage unit. To provide protection against corrosion caused by the saturated exhaust gases, the cold end plates are manufactured from stainless steel 304. The hot section operates above the water dew point and is manufactured from carbon steel.

Static Gas Mixers (SGM)

The static mixer utilizes the effects of a vortex (picture 3), produced when a disc or delta wing is positioned at a specific angle to a gaseous stream. There are several locations in the SCR system that use the beneficial effects of this devise.

Picture 3 (Vortex Formation)

Pre & Post Bleed Gas Locations – The static gas mixer is used to mix the 1700°F bleed gases with the dirty exhaust gases.

Ammonia Injection – The SGM is used to mix the atomized 19% aqueous ammonia with the hot dirty exhaust gases. The SGM technology permits the direct injection of the aqueous ammonia into the gas stream without the use of external vaporizers. There are three discs at this location and each one has an ammonia injection nozzle located at the center. Therefore only three ammonia nozzles are required for the complete SCR process.

Homogenizers – After the ammonia has been injected into the exhaust stream, additional SGM's and turning vanes are provided to ensure the homogeneous distribution of the gas, NOx, ammonia and temperature. Good distribution of these elements is required to maximize the catalyst function and reduce the ammonia slip to a minimum.

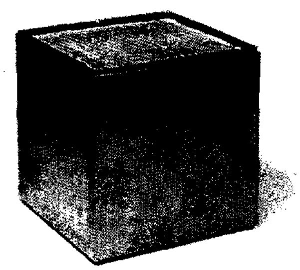
Injection Nozzles

Three Lechler nozzles are installed to atomize the 19% aqueous ammonia (using small amounts of 100 psig, dry, compressed air). The ammonia is supplied at a pressure of 60 – 70 psig.

Catalyst

The NOx catalyst is a Haldor Topsoe DNX- 930, which is a low pressure drop honeycomb design comprised of Titanium Dioxide, Vanadium Pentoxide and Tungsten Trioxide.

Picture 4 (Typical Catalyst Module)



A spare catalyst layer is designed into the system so that additional catalyst can be added in the future, as the reactivity of the original catalyst declines.

Flow Modeling

A plexi-glass 35:1scale model is produced incorporating the static gas mixers. Adjustments are made to produce the required flow patterns for the exhaust gases, ammonia injection, temperature and NOx distribution.

System Pressure Drop

The Compact DeNOx system is designed for an overall pressure drop of 12-inches WC. Higher pressure drops can be used to reduce system size however the SCV blowers will require additional horsepower resulting in an increase in operational costs. The reverse is true if lower pressure drops are selected.

Operating Issues & Remedies

There have been two areas where design decisions have resulted in operational issues, and although two parts of the system have been affected, the root cause can be traced to the hot bleed gas heating system.

Hot Bleed Gas System

Shortly after start-up, water entered the hot bleed gas piping; it is still unclear if this was a result of water droplet entrainment from the water bath or a leak from the SCV distribution system. The water saturated the hard core ceramic internal liner leaving the soft fibrous insulation unprotected from the gas stream velocities. This resulted in insulation releasing from the duct walls plugging the catalyst with ceramic fiber. With the internal insulating material dislodged, the hot bleed gas system could not be used and therefore the SCR system operated with the saturated exhaust gases for an extended period of time.

A different type of internal insulation was installed, but again water affected the system. The problem was finally remedied by changing the bleed gas duct to an externally insulated system. The expansion problems that were an initial concern have not materialized and the connecting duct issues appear to have been solved. A droplet separator has also been installed upstream of the SCR system.

The seals on the high temperature control valves have produced maintenance issues; this in turn has led to water incursion into the bleed gas system. These valves have been rebuilt and the temperature of the bleed gas reduced to prolong the life expectancy of these seals.

Catalyst

Due to the low temperatures present in the water bath of the SCV and the moisture content of the LNG gas being fired in the burner, condensation takes place in the water bath resulting in a net increase of water. Combustion gases passing through the water bath produce several dilute acids such as carbonic and nitric acid. These acids reduce the ph to the 3 – 4 level. This acidic water is dosed with Sodium Carbonate to balance the ph, prior to being returned to the Charles River; unfortunately Sodium is a poison to the NOx catalyst.

When the SCR system was operated without bleed gas heating, the saturated gases passed over the catalyst, before its removal. Once the dried out catalyst was reinstalled and heat restored to the system. Sodium deposited on the catalyst during the saturated operation remained; this significantly reduced the reactivity of the catalyst, which had to be replaced.

Initially the complete water bath was neutralized with sodium carbonate, now an overflow system has been installed and only the water going to discharge is treated. However, a small amount of water is injected into the SCV burner to limit NOx formation, and this water contains the sodium carbonate. Provided the SCR system is operated at design conditions and temperatures, this sodium should pass through the system without creating problems. Further operating experience will determine if this is correct. An alternative to sodium carbonate would be to use ammonia as the dosing chemical; this would alleviate the potential for sodium poisoning, although increasing operating costs.

Conclusions

As a number of companies consider building and permitting additional vaporization facilities in various parts of the United States, the integrated SCV and SCR System is a viable option, particularly in circumstance where low NOx burners cannot meet emission levels. The system installed in downtown Boston is meeting and exceeding all the environmental requirements of 5-ppm NOx and 5-ppm ammonia slip. The majority of the operational issues can be traced back to the hot bleed gas heating system and while this is the most efficient system, the reliability has to be questioned.

To reduce the amount of entrained water droplets entering the SCR system, installation of a moisture separator in the upstream ductwork is recommended.

If high pressure and temperature steam is available this is the simplest form of supplying the necessary heat. In most cases however, this option is not available. Installation of a direct-fired remote air heater can duplicate the hot bleed gas system although at a lower efficiency. This option reduces the SCR's reliance on the SCV and will permit independent operation.

Reducing the gas temperature from 1,700°F to approximately 1,100°F will permit the use of stainless steel 304 (less expensive than the Inconel used with1,700°F) with external insulation, thus avoiding the potential fouling of the catalyst and heat exchanger.

If a bypass system cannot be installed to isolate the SCR and permit SCV operation, then during extended periods of cold operation, the catalyst should be removed to prevent degradation. In the case presented the catalyst can be removed in approximately 6 – 8 hours.

More operating experience needs to be acquired to see if dosing with Sodium Carbonate will have a long-term effect on catalyst life expectancy. However, an alternative is available with the use of ammonia albeit at a higher operating cost.

Acknowledgements

Balcke-Dürr AG - the original developer of the Compact DeNOx System

GEA Ecoflex GmbH – the current supplier of the Compact DeNOx Technology

Professor Hans Ruscheweyh – the developer of the Static Gas Mixer

Aker-Kvaerner – the initial design engineering company for Cabot- Distrigas

Distrigas – The management and operations personnel for all their assistance and candidness in discussing the plant operations.

Disclaimer

The views expressed in this paper are solely the author's and are based on site visits, discussions and knowledge of the design decisions that resulted in the system presented. They may not reflect the views of other participants in the project and should not be construed to represent the views of the current owner of the facility under discussion, Tractebel-Distrigas.

MSDS ***Material Safety Data Sheet***

24 Hour Emergency Telephone: 908-859-2151
CHEMTREC: 1-800-424-9300

National Response in Canada
CANUTEC: 613-996-6666

Outside U.S. and Canada
Chemtrec: 703-527-3887

From: Mallinckrodt Baker, Inc.
222 Red School Lane
Phillipsburg, NJ 08865

Mallinckrodt CHEMICALS

J.T.Baker

NOTE: CHEMTREC, CANUTEC and National Response Center emergency numbers to be used only in the event of chemical emergencies involving a spill, leak, fire, exposure or accident involving chemicals.

All non-emergency questions should be directed to Customer Service (1-800-582-2537) for assistance.

SODIUM CARBONATE ANHYDROUS

1. Product Identification

Synonyms: Carbonic acid, disodium salt; disodium carbonate; soda ash
CAS No.: 497-19-8
Molecular Weight: 105.99
Chemical Formula: Na2CO3
Product Codes:
J.T. Baker: 3602, 3604, 3605, 3606, 4502, 4923, 5198
Mallinckrodt: 1338, 3604, 7468, 7472, 7521, 7527, 7528, 7698

2. Composition/Information on Ingredients

Ingredient	CAS No	Percent	Hazardous
Sodium Carbonate	497-19-8	99 - 100%	Yes

3. Hazards Identification

Emergency Overview

DANGER! MAY CAUSE EYE BURNS. HARMFUL IF SWALLOWED OR INHALED. CAUSES IRRITATION TO SKIN AND RESPIRATORY TRACT.

SAF-T-DATA$^{(tm)}$ Ratings (Provided here for your convenience)

Health Rating: 1 - Slight
Flammability Rating: 1 - Slight
Reactivity Rating: 2 - Moderate
Contact Rating: 3 - Severe (Life)
Lab Protective Equip: GOGGLES & SHIELD; LAB COAT & APRON; VENT HOOD; PROPER GLOVES
Storage Color Code: Green (General Storage)

Potential Health Effects

Inhalation:
Inhalation of dust may cause irritation to the respiratory tract. Symptoms from excessive inhalation of dust may include coughing and difficult breathing. Excessive contact is known to cause damage to the nasal septum.
Ingestion:
Sodium carbonate is only slightly toxic, but large doses may be corrosive to the gastro-intestinal tract where symptoms may include severe abdominal pain, vomiting, diarrhea, collapse and death.
Skin Contact:
Excessive contact may cause irritation with blistering and redness. Solutions may cause severe irritation or burns.
Eye Contact:
Contact may be corrosive to eyes and cause conjuctival edema and corneal destruction. Risk of serious injury increases if eyes are kept tightly closed. Other symptoms may appear from absorption of sodium carbonate into the bloodstream via the eyes.
Chronic Exposure:
Prolonged or repeated skin exposure may cause sensitization.
Aggravation of Pre-existing Conditions:
No information found.

---

4. First Aid Measures

Inhalation:
Remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Get medical attention.
Ingestion:
If swallowed, DO NOT INDUCE VOMITING. Give large quantities of water. Never give anything by mouth to an unconscious person. Get medical attention immediately.
Skin Contact:
Immediately flush skin with plenty of soap and water for at least 15 minutes. Remove contaminated clothing and shoes. Get medical attention. Wash clothing before reuse. Thoroughly clean shoes before reuse.

Eye Contact:
Immediately flush eyes with plenty of water for at least 15 minutes, lifting lower and upper eyelids occasionally. Get medical attention immediately.

Note to Physician:
Consider endoscopy in all suspected cases of sodium carbonate poisoning. Perform blood analysis to determine if dehydration, acidosis, or other electrolyte imbalances occurred.

---

5. Fire Fighting Measures

Fire:
Not considered to be a fire hazard.
Explosion:
Not considered an explosion hazard, but sodium carbonate may explode when applied to red-hot aluminum.
Fire Extinguishing Media:
Use any means suitable for extinguishing surrounding fire.
Special Information:
Use protective clothing and breathing equipment appropriate for the surrounding fire.

---

6. Accidental Release Measures

Ventilate area of leak or spill. Wear appropriate personal protective equipment as specified in Section 8. Spills: Sweep up and containerize for reclamation or disposal. Vacuuming or wet sweeping may be used to avoid dust dispersal.

---

7. Handling and Storage

Keep in a tightly closed container, stored in a cool, dry, ventilated area. Protect against physical damage. Isolate from incompatible substances. Containers of this material may be hazardous when empty since they retain product residues (dust, solids); observe all warnings and precautions listed for the product.

---

8. Exposure Controls/Personal Protection

Airborne Exposure Limits:
None established.
Ventilation System:
A system of local and/or general exhaust is recommended to keep employee exposures as low as possible. Local exhaust ventilation is generally preferred because it can control the emissions of the contaminant at

its source, preventing dispersion of it into the general work area. Please refer to the ACGIH document, *Industrial Ventilation, A Manual of Recommended Practices*, most recent edition, for details.
Personal Respirators (NIOSH Approved):
For conditions of use where exposure to dust or mist is apparent and engineering controls are not feasible, a particulate respirator (NIOSH type N95 or better filters) may be worn. If oil particles (e.g. lubricants, cutting fluids, glycerine, etc.) are present, use a NIOSH type R or P filter. For emergencies or instances where the exposure levels are not known, use a full-face positive-pressure, air-supplied respirator. WARNING: Air-purifying respirators do not protect workers in oxygen-deficient atmospheres.
Skin Protection:
Wear protective gloves and clean body-covering clothing.
Eye Protection:
Use chemical safety goggles and/or full face shield where dusting or splashing of solutions is possible. Maintain eye wash fountain and quick-drench facilities in work area.

---

9. Physical and Chemical Properties

Appearance:
White powder or granules.
Odor:
Odorless.
Solubility:
45.5 g/100 ml water @ 100C (212F)
Specific Gravity:
2.53
pH:
11.6 Aqueous solution
% Volatiles by volume @ 21C (70F):
0
Boiling Point:
Decomposes.
Melting Point:
851C (1564F)
Vapor Density (Air=1):
No information found.
Vapor Pressure (mm Hg):
No information found.
Evaporation Rate (BuAc=1):
No information found.

---

10. Stability and Reactivity

Stability:
Stable under ordinary conditions of use and storage. Hygroscopic. Readily absorbs moisture from the air. Solutions are strong bases.
Hazardous Decomposition Products:
Oxides of carbon and sodium oxide.

Hazardous Polymerization:
Will not occur.
Incompatibilities:
Fluorine, aluminum, phosphorous pentoxide, sulfuric acid, zinc, lithium, moisture, calcium hydroxide and 2,4,6-trinitrotoluene. Reacts violently with acids to form carbon dioxide.
Conditions to Avoid:
Moisture, heat, dusting and incompatibles.

---

11. Toxicological Information

For Sodium Carbonate:
Oral rat LD50: 4090 mg/kg; inhalation rat LC50: 2300 mg/m3/2H; irritation eye rabbit: 50 mg severe; investigated as a mutagen, reproductive effector.

--------\Cancer Lists\--

Ingredient	---NTP Carcinogen--- Known	Anticipated	IARC Category
Sodium Carbonate (497-19-8)	No	No	None

---

12. Ecological Information

Environmental Fate:
No information found.
Environmental Toxicity:
96 Hr LC50 Lepomis macrochirus: 300 mg/L [static];
48 Hr EC50 Daphnia magna: 265 mg/L

---

13. Disposal Considerations

Whatever cannot be saved for recovery or recycling should be managed in an appropriate and approved waste disposal facility. Processing, use or contamination of this product may change the waste management options. State and local disposal regulations may differ from federal disposal regulations. Dispose of container and unused contents in accordance with federal, state and local requirements.

---

14. Transport Information

Not regulated.

---

15. Regulatory Information

--------\Chemical Inventory Status - Part 1\----------------------------------

Ingredient	TSCA	EC	Japan	Australia
Sodium Carbonate (497-19-8)	Yes	Yes	Yes	Yes

--------\Chemical Inventory Status - Part 2\----------------------------------

		--Canada--		
Ingredient	Korea	DSL	NDSL	Phil.
Sodium Carbonate (497-19-8)	Yes	Yes	No	Yes

--------\Federal, State & International Regulations - Part 1\----------------

	-SARA 302-		------SARA 313------	
Ingredient	RQ	TPQ	List	Chemical Catg.
Sodium Carbonate (497-19-8)	No	No	No	No

--------\Federal, State & International Regulations - Part 2\----------------

		-RCRA-	-TSCA-
Ingredient	CERCLA	261.33	8(d)
Sodium Carbonate (497-19-8)	No	No	No

Chemical Weapons Convention: No TSCA 12(b): No CDTA: No
SARA 311/312: Acute: Yes Chronic: No Fire: No Pressure: No
Reactivity: No (Pure / Solid)

Australian Hazchem Code: None allocated.
Poison Schedule: S5
WHMIS:
This MSDS has been prepared according to the hazard criteria of the Controlled Products Regulations (CPR) and the MSDS contains all of the information required by the CPR.

---

16. Other Information

NFPA Ratings: Health: **2** Flammability: **0** Reactivity: **0**
Label Hazard Warning:
DANGER! MAY CAUSE EYE BURNS. HARMFUL IF SWALLOWED OR INHALED. CAUSES IRRITATION TO SKIN AND RESPIRATORY TRACT.
Label Precautions:
Do not get in eyes, on skin, or on clothing.
Avoid breathing dust.
Keep container closed.
Use with adequate ventilation.
Wash thoroughly after handling.
Label First Aid:
In case of contact, immediately flush eyes or skin with plenty of water for at least 15 minutes while

removing contaminated clothing and shoes. Wash clothing before reuse. If swallowed, DO NOT INDUCE VOMITING. Give large quantities of water. Never give anything by mouth to an unconscious person. If inhaled, remove to fresh air. Get medical attention for any breathing difficulty. In all cases, get medical attention.

Product Use:

Laboratory Reagent.

Revision Information:

MSDS Section(s) changed since last revision of document include: 12.

Disclaimer:

Prepared by: Environmental Health & Safety
Phone Number: (314) 654-1600 (U.S.A.)

Shah, Kamal

From: Dave Hawkins [djh@bdheat.com]

Sent: Tuesday, October 31, 2006 1:22 PM

To: Shah, Kamal

Subject: Fw: Fw: SCR for SCV unit

Dear Kamal:

I trust this helps regarding the current catalyst conditions, as I said previously an alternative to sodium carbonate would resolve a majority of the problems

Best Regards

Dave Hawkins
----- Original Message -----
From: Flemming Hansen
To: Dave Hawkins
Sent: Monday, October 30, 2006 4:40 PM
Subject: Re: Fw: SCR for SCV unit

Dave,
I haven't talked to Connie Martin for a couple of months, but we have been in contact with their consultant Careba Power.
We found that the catalyst got contaminated with Sodium and it has been replaced after about 18 months of service. Careba has confirmed that there is a carryover of sodium carbonate from the SCV and we have been discussing alternative buffers.
So far no good alternative has been agreed upon.

The sodium both poisons and masks the catalyst. Sodium will block the acid sites on the catalyst and prevent ammonium from adsorbing. But at DistriGas there is so much that it actually lays down on top of the catalyst as well, like fly ash in a coal fired boiler. We have therefore also suggested they look at using both catalyst layers and use a more open pitched catalyst. This may be used in the future.

On your question on methane then it will pass through the SCR catalyst as an inert. Higher hydrocarbons like propane, butane etc will adsorb into the catalyst pores and will ignite when the conditions are right. An overheating of the catalyst will then ensue and the catalyst is irreparably damaged. I don't think a CO catalyst will burn off methane and ethane in the small quantities normally seen. Higher HCs will most likely all be destroyed.

Let me know if I can help further.

Thanks

Flemming G. Hansen
Manager SCR DeNOx Catalyst
Haldor Topsoe, Inc.
281-228-5120 (office)
281-228-5129 (fax)
281-684-8820 (cell)
FGH@Topsoe.com
www.topsoe.com

BASF

Nitrogen derivates

Ammonium carbonate (E 503i)

See also: Ammonium bicarbonate

Product description

Fine white crystals with a strong ammonia odour.

Nature	Ammonium carbonate, diammonium salt of carbonic acid, $(NH_4)_2CO_3$. 1:1 mixture of ammonium hydrogen carbonate (NH_4HCO_3) and ammonium carbamate (NH_4COONH_2).
Trade name	Ammonium carbonate
Formula	$H_2CO_3 \times NH_3$
CAS No.	10361-29-2
EINECS No.	233-786-0

Packaging

Supplied in 25-, 50- or 160 kg-packaging.

Properties

Ammonium carbonate is a 1:1 mixture of ammonium hydrogen carbonate and ammonium carbamate. Readily soluble in water. Liberates gaseous carbon dioxide on treatment with acids and gaseous ammonia on treatment with alkalis.

Thermal decomposition	above 59 °C completely decomposed to ammonia, water and carbon dioxide
Vapour pressure (20 °C)	69 mbar
Vapour pressure (30 °C)	188 mbar
Density (20 °C)	1.6 g/cm³
Bulk density	780 - 830 kg/m³
Solubility in water (20 °C)	320 g/l
pH value (100 g/l, 20 °C)	9

Product specification

See specification ammonium carbonate.

Approvals

Ammonium carbonate fulfils the purity criteria for food additives set by EU Directive 97/77/EU, the Joint (FAO/WHO) Expert Committee on Food Additives (JECFA) in the Codex Alimentarius as well as the one contained in the Food Chemical Codex 2004 5th edithion, FCC V. It fulfils also the specification's limits of the US Pharmacopeia 27. For use as a food additive, ammonium carbonate has a limited license according to E-No. 503 i.

Certificates

See certificate DIN EN ISO 9001:2000. A **HACCP** system has been introduced, which is constantly refined, see Confirmation HACCP System. The production of the products effected in accordance with GMP, see confirmation management System GMP regulations. The plant had been certified according BRC global standard - to Food, see certificate BRC global standard - Food. A **Kashrut certificate and a Halal confirmation** are available.

Storage and transport

Ammonium carbonate must be kept cool and dry in a well-ventilated place. If it is exposed to air, gaseous ammonia and carbon dioxide are liberated with an attendant loss in weight. Containers must be ventilated before unloading because of the ammonia odour.
Loses its free-flowing quality within a few days and tends to cake. However this does not impair the products performance.

Applications

In the chemical and pharmaceutical industry: For analytical purposes. In the production of organic compounds, e.g. heterocycles. To manufacture catalysts.
In the chemical processing industry: As a blowing agent for manufacturing foam plastics and rubber. In the production of casein colours, casein glues and other adhesives. As an additive in photographic developers.
In the textile industry: For neutralising in the carbonisation process. In dyeing as a base that can be readily removed by boiling. As a neutralising agent in hat manufacture.
In the cosmetics industry: As an additive for shampoos and hair lotions. For smelling salts.
In the food Industry: In some countries ammonium carbonate is used as a leavening agent for

gingerbread and dry biscuits. The carbon dioxide released during heating is decisive for the leavening power.

As an additive in **processing uranium** (as ammonium uranyl carbonate in the AUC process).

In the **production of strippers**: Nickel and copper coats can be stripped off steel, plastic and zinc-die-casting surfaces with solutions of this kind.

Safety

Harmful if swallowed. Liberation of ammonia at elevated temperature. Ammonium carbonate reacts with nitrites and nitrates (even at room temperature). The reaction can cause flame.

During the handling of this product the data and reference in the safety data sheet are to be considered. In addition the necessary caution and good industrial hygiene while handling chemicals have to been kept.

January 2005

last modified: May 3, 2005

back print bookmark top

SELAS FLUID PROCESSING CORP.	DATE: 2/18/05	
BLUE BELL, PA	DOC NO:	
	SFPC PROJ. NO.: 04122V	
VAPORIZER DATA SHEET	ISSUE: B (Proposal)	BY: CDS
	ISSUE:	CHECK:

					REV.
1	**PURCHASER / OWNER:**	BHP Billiton	**ITEM NO. :**	F101A to F101F	
2	**SERVICE:**	Vaporize LNG	**LOCATION:**	Outdoor, Floating Platform	
3	MODEL:	Sub-X 120-180 t/hr Low Emissions	DRY WT., lb:		
4	NO. REQUIRED:	8			
5	TYPE:	Submerged Combustion	NO. BURNERS:	1 per unit	

6 **PROCESS DESIGN CONDITIONS**

7	**CASE**	Scarborough					
8		(Design Basis)					
9	**AMBIENT CONDITIONS**						
10	TEMPERATURE, °F	60					
11	PRESSURE, PSI	14.7					
12	RELATIVE HUMIDITY	60%					
13							
14	**LNG DESCRIPTION**						
15	CH_4 MOLE %	99.68%					
16	C_2H_6 MOLE %	0.11%					
17	C_3H_8 MOLE %	0.00%					
18	C_4H_{10} MOLE %	0.00%					
19	C_5H_{12} MOLE %	0.00%					
20	N_2 MOLE %	0.20%					
21	MW	16.1					
22	VAPORIZATION RATE, MM SCFD	202.8					
23	VAPORIZATION RATE, LB/HR	357,899	162.3 t/hr				
24	LNG INLET TEMPERATURE, °F	-258	-161°C				
25	NG OUTLET TEMPERATURE, °F	41	5°C				
26	NG OUTLET PRESSURE, PSIG	1,400	96.5 bar g				
27	DUTY, MM BTU/HR	112.7	33.0 MW				
28	VAPORIZER SEND OUT RATE, MM SCFD	221.9	177.6 t/hr	see note 5			
29	**FUEL DESCRIPTION**						
30	CH_4 MOLE %	98.06%					
31	C_2H_6 MOLE %	0.06%					
32	C_3H_8 MOLE %	0.00%					
33	C_4H_{10} MOLE %	0.00%					
34	C_5H_{12} MOLE %	0.00%					
35	N_2 MOLE %	1.87%					
36	HEATING VALUE (HHV), BTU/SCF	990					
37	HEATING VALUE (HHV), BTU/LB	23,105					
38	FUEL INLET TEMPERATURE, °F	60					
39	FUEL OUTLET TEMPERATURE, °F	N/A					
40	FUEL OUTLET PRESSURE, PSIG	N/A					
41	**CALCULATED VALUES**						
42	WATER OVERFLOW RATE, GPM	17.1					
43	FUEL RATE, SCFH	116,087					
44	PROCESS PRESSURE DROP, PSI	50.0					
45	PROCESS INLET PRESSURE, PSIG	1,450					
46	EFFICIENCY (HHV)	98%					
47	BATH TEMPERATURE, °F	83					
48	FUEL PRESSURE DROP, PSI	N/A					
49							
50	FLUE GAS						
51	CO_2 MOLE %	6.6%					
52	N_2 MOLE %	81.5%					
53	O_2 MOLE %	8.0%					
54	H_2O MOLE %	3.9%					
55	FLOW RATE, SCFM	28,605					
56	TEMPERATURE, °F	83					

SELAS FLUID PROCESSING CORP.	DATE: 2/18/05 PAGE 2 OF 3
BLUE BELL, PA	DOC NO:
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	ISSUE: CHECK:

TUBE BUNDLE DETAILS

	Process Bundle			Fuel Pre-heat Bundle			REV.
INLET HEADER CONNECTION	304/304L SS	8" 900# Flange					
OUTLET HEADER CONNECTION	304/304L SS	12" 900# Flange					
TUBES	304/304L SS	1.125" OD. 0.083" Avg Wall					
PASSES	8						
HEAT TRANSFER AREA. FT^2	3864						
DESIGN PRESSURE. PSIG	2030	(Design Basis)					
DESIGN TEMPERATURE, min/max, °F	-320 / +150						
DESIGN CODE	ASME SECTION VIII (Stamped). T-Thermal Spec. 211A			ASME SECTION VIII (Stamped), T-Thermal Spec. 211A			

TANK DETAILS

			REV.
TANK	MATERIAL:	Stainless Steel	
LENGTH	40' -0" (INSIDE TANK WALL)		
WIDTH	16'-0" (INSIDE TANK WALL)		
HEIGHT	12' (FLOOR TO BOTTOM TANK TOP)		
DOWNCOMER/DISTRIBUTOR:	MATERIAL:	304 SS	
WEIR:	MATERIAL:	304 SS	
COVER PLATE:	MATERIAL:	304 SS	
DEMISTER:			
CONNECTIONS			
DRAIN	6" 150# RF FLANGE (BY PURCHASER)		
OVERFLOW	3" 150# RF FLANGE (BY PURCHASER)		

OTHER CONNECTIONS

		REV.
FUEL	4" 150# RF FLANGE	
INSTRUMENT AIR	1" 150# RF FLANGE	
WATER	3" 150# RF FLANGE	

STACK

				REV.
DIAMETER	4'-9" ID			
HEIGHT	TBD			
MATERIAL	CARBON STEEL			
LOCATION	TBD			
CONNECTIONS	SIZE	TYPE	QUANTITY	
TEMP SWITCHES	3/4"	3000# COUPLING	1	
TEMP ELEMENTS	3/4"	3000# COUPLING	1	
COMUSTIBLE ANALYZER	4"	150# FLANGE	1	
EPA TEST PORTS	2"	150# FLANGE	2	

LINE DESCRIPTIONS

LINE	**SIZE**	**MATERIAL**	REV.
COMBUSTION AIR MAIN	24"	CARBON STEEL	
COMBUSTION AIR PRIMARY	12"	CARBON STEEL	
COMBUSTION AIR SECONDARY	24"	CARBON STEEL	
FUEL MAIN	4"	CARBON STEEL	
FUEL - 1st STAGE	3/4"	CARBON STEEL	
FUEL - 2nd STAGE	1"	CARBON STEEL	
WATER - PUMP INLET	3"	STAINLESS STEEL	
WATER - PUMP OUTLET	2"	STAINLESS STEEL	
WATER - BURNER JACKET	2"	STAINLESS STEEL	
WATER - AIR NOZZLE	1"	STAINLESS STEEL	
WATER - NO_x REDUCTION	1"	STAINLESS STEEL	

PRINTED: 18-Feb-05 16:42

SELAS FLUID PROCESSING CORP. **BLUE BELL, PA**	DATE: 2/18/05 PAGE 3 OF 3
	DOC NO:
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VAPORIZER DATA SHEET	ISSUE: B (Proposal) BY: CDS
	ISSUE: CHECK:

GUARANTEES

					REV.
CONDITION					
AMBIENT CONDITIONS					
TEMPERATURE, °F					
PRESSURE, PSI					
RELATIVE HUMIDITY					
LNG DESCRIPTION					
CH_4 MOLE %					
C_2H_6 MOLE %					
C_3H_8 MOLE %					
C_4H_{10} MOLE %					
C_5H_{12} MOLE %					
N_2 MOLE %					
VAPORIZATION RATE, MM SCFD					
VAPORIZATION RATE, LB/HR					
LNG INLET TEMPERATURE, °F					
NG OUTLET TEMPERATURE, °F					
NG OUTLET PRESSURE, PSIG					
VAPORIZER SEND OUT RATE, MM SCFD					
FUEL DESCRIPTION					
CH_4 MOLE %					
C_2H_6 MOLE %					
C_3H_8 MOLE %					
C_4H_{10} MOLE %					
C_5H_{12} MOLE %					
N_2 MOLE %					
GUARANTEES					
PRESSURE DROP, PSI	< 50				
EFFICIENCY (HHV)	> 98%				
NO_x CONCENTRATION	< 20	ppmvd as NO_2 (corrected to 3% O_2)			
CO CONCENTRATION	< 100	ppmvd (corrected to 3% O_2)			

NOTES

1) Efficiency (HHV) is defined as:

$$\frac{\text{Heat Transferred}}{\text{Fuel Firing Rate}} = \frac{357{,}899 \text{ lb/hr} * 315 \text{ Btu/lb}}{48107 \text{ lb/hr} * 23.105 \text{ Btu/lb}} = \frac{112.7 \text{ MM Btu/hr}}{115.0 \text{ MM Btu/hr}} = 98.0\%$$

2) Comparison of Calculated (Design) Values and Guaranteed Values (at the basis of 60°F, 60% RH ambient conditions)

		Calculated Value	Guaranteed Value
HHV Efficiency	%		
Send Out Rate	MM SCFD		
Pressure Drop	PSI		

3) At lower operating pressures, the calculated heat duty would be greater. Therefore, the expected vaporization rate shall be reduced.

4) For an LNG with lower methane content, the calculated duty would be greater. Therefore, the expected vaporization rate shall be reduced.

5) Vaporizer send out rate is defined as the vaporization rate minus the fuel consumed by the vaporizer burner(s).

6) The above values are based on a high excess air burner.

PRINTED: 18-Feb-05 16:42

From: Minton, Bill
Sent: Wednesday, November 08, 2006 12:36 PM
To: 'mike.durilla@basf.com'
Subject: RE: CO Oxidation catalyst

Thanks.

-----Original Message-----
From: mike.durilla@basf.com [mailto:mike.durilla@basf.com]
Sent: Wednesday, November 08, 2006 9:49 AM
To: Minton, Bill
Cc: william.hizny@basf.com
Subject: RE: CO Oxidation catalyst

I would caution your conclusion.

Standard oxidation catalysts are not used to combust methane because the methane is very difficult to ignite. Methane levels are typically low so if some methane does convert no one usually cares. However, under some conditions you could start the reaction locally on the catalyst.
(Directionally, if I put a lot of PM on the surface, I can get ignition.) The issue is that if the methane starts to combust and you have a lot of it, you might locally generate a hot spot. Normally, with methane, the ignition area on the catalyst surface can experience a lot of thermal shock which could damage the surface.

I would at least check the potential exotherm from the methane assuming it all converts and see where that takes you. If the temperature rise is small, it is probably not an issue.

I would suggest a flammability consultant would be better able to comment about safety. Most catalyst suppliers will list the catalyst as a potential ignition source on their MSDS sheets and that would be a red flag should there be a problem later.

Michael Durilla
Applications Manager

Stationary Source & Indoor Air
Environmental Technologies
Telephone: 732-205-6644
Fax: 732-206-6174
E-mail: mike.durilla@basf.com

BASF Catalysts LLC
101 Wood Avenue, P.O. Box 770
Iselin, NJ 08830-0770

BASF - The Chemical Company

Minton, Bill

From: Minton, Bill
Sent: Wednesday, November 08, 2006 9:24 AM
To: 'mike.durilla@basf.com'
Subject: RE: CO Oxidation catalyst

I think you have just answered my question. It is a safety issue. If we rupture a tube in a methane heater, will the methane that suddenly appears in the heater's exhaust react with the oxygen in the exhaust as it passes over the CO catalyst? As I read your message below, the catalyst will not initiate an oxiation reaction with methane.

-----Original Message-----
From: mike.durilla@basf.com [mailto:mike.durilla@basf.com]
Sent: Wednesday, November 08, 2006 9:17 AM
To: Minton, Bill
Cc: stan.mack@basf.com; william.hizny@basf.com
Subject: Fw: CO Oxidation catalyst

It is not clear to me from your e-mail what you are asking for.

We do sell oxidation catalysts. They are typically used to covert CO and/or NMHC. We do not have any catalyst that would oxidize methane.

When I think of a tube leak, I think of a heat transfer fluid of some sort potentially contacting the catalyst. In that case, we are normally concerned about additives in the fluid contaminating the catalyst rather than the catalyst oxidizing the heat transfer fluid. (However, if the fluid contains organics, they can potentially oxidize on the catalyst and generate an exotherm.)

Oxidation catalysts can be a source of ignition.

Michael Durilla
Applications Manager

Stationary Source & Indoor Air
Environmental Technologies
Telephone: 732-205-6644
Fax: 732-206-6174
E-mail: mike.durilla@basf.com

BASF Catalysts LLC
101 Wood Avenue, P.O. Box 770
Iselin, NJ 08830-0770

BASF - The Chemical Company

<Bill.Minton@aker
kvaerner.com>

11/08/2006 08:27
AM

To
<nancy.ellison@engelhard.com>

cc

Subject
CO Oxidation catalyst

We have an application for an oxidation catalyst to be installed ahead of a DeNox catalyst in a process heater exhaust. The heater is heating methane, and the client has asked what happens if there is a tube leak? Does this create a hot spot?, fire?, explosion? There is approximately 5% oxygen in the exhaust stream.

Any information you can give us will be appreciated.

Bill Minton, Process Consultant
Aker Kvaerner
3600 Briarpark Drive
Houston, Texas 77042

713/270-2572
Bill.minton@akerkvaerner.com

Lower Emission LNG Vaporization

C.C. Yang and Zupeng Huang, Foster Wheeler North America Corporation, USA

This article compares the different types of LNG vaporizers in use and their environmental impact, and describes a vaporization concept using waste heat from power plant or industrial facilities that eliminates fuel requirements, while reducing emissions and improving thermal efficiency.

The selection of LNG vaporizers for LNG receiving terminals has recently been more critically evaluated for the impact of the discharges of the flue gas and/or seawater on the environment compared to the traditional LNG vaporizers.

There are several types of LNG vaporizers commonly used. The following five types have either been used or demonstrated in LNG receiving terminals:

(a) Open Rack Vaporizers (ORV)
(b) Submerged Combustion Vaporizers (SCV)
(c) Shell and Tube type Vaporizers (STV) including modified designs such as the Reli-Vap type vaporizer.
(d) Combined Heat and Power unit with Submerged Combustion Vaporizer (CHP-SCV)
(e) Other type of Vaporizers - Ambient Air-Heated Vaporizers

The main manufacturers are shown in Table 1. Key issues to be considered in the evaluation and selection of vaporizer type are:

- Availability and quality of seawater
- Capital cost and fuel cost
- Environmental issues such as air and water emissions

Table 1: Vaporizer Vendors

Submerged Combustion Vaporizers (SCV)
T-Thermal, USA
Kaldair Ltd., UK
Sumitomo Precision, Japan

Open Rack Vaporizers (ORV)
Kobe Steel Kobelco, Japan
Sumitomo, Japan

Shell and Tube Type Vaporizers (STV) and Intermediate Fluid Vaporizer
Kobe Steel, Japan
Chicago Power & Process, USA
Wheaton Process Systems, USA

Combined Heat and Power Unit (CHP)
Tractebel Group, Belgium

LNG receiving terminals commonly use one of two types of LNG vaporizers: the ORV and the SCV. In general the ORV system uses seawater as the heat medium. It has a lower operating cost than the SCV, but normally a higher capital cost because of the vaporizer equipment cost, the added seawater intake/outfall system, the large diameter seawater pipes, and the seawater pumping and treating systems The SCV requires fuel for the LNG vaporization, and the fuel consumption is about 1.5% of the send-out gas. Thus, it has a higher operating cost than the ORV as the fuel has a significant economic value at the LNG terminals. STVs, including the Intermediate Fluid Type LNG Vaporizers, have been used in LNG receiving terminals by rejecting cold to the seawater or a heat transfer medium, and have been used in the application of utilizing LNG cold for pre-cooling the air in power plant applications.

Operational Issues of LNG Vaporizers

Open Rack Vaporizers (ORV): ORVs use ambient seawater as their source of heat in an open, falling film type arrangement to vaporize LNG passing through the tubes. ORVs are widely used in Japan, Korea and Europe, and are well proven in baseload LNG terminal service. In general, for using ORVs the preferred seawater temperature is always above 8 °C.

General Description: The ORV is made of an aluminum alloy for good mechanical characteristics at low temperatures, excellent workability, and high thermal conductivity. Seawater is fed from an overhead distributor, flows downwards over the outer surface of long finned tube heat exchanger panels, vaporizing the LNG flowing inside, and is collected in a trough below where it is routed and discharged back to the sea. The panels are coated externally with zinc alloy, providing corrosion resistance against seawater. ORVs require regular (usually annual) maintenance to keep the finned tube surface clean.

The seawater is chlorinated to protect the surface of the tube panel against bio-fouling and to prevent marine growth inside the piping. Fluctuations in product gas demand, gas outlet temperature and seawater temperature will be handled by turndown of the unit, which can be over 90%.

Water Quality: Water quality is a critical requirement for successful operation of an ORV system. Key requirements are:

- Significant amounts of water. This will lead to a requirement to carefully evaluate and assess the amount of underwater fish and plant life that are ingested by the intake system. Often, significant design requirements will be involved to minimize this.
- Chlorination for water treatment is desirable: however residual chlorine content can have a negative impact on the marine environment by killing significant marine life. This can be minimized by "shock" treatment of chlorine.
- The water should not contain solids exceeding 2 mm in diameter in order to assure uniform water flow without jamming of the solids between the water trough and the top of the tube panel.
- Water containing heavy metal ions, Cu^{++}, Hg^{++}, must not be used in the water lines, as these ions will shorten the lifetime of zinc-aluminum spray coating on the tubes. $Cu^{++} < 10$ ppb and $Hg^{++} < 2$ ppb are required.
- Sand and sludge deposits contained in sea or fresh water must be negligible. Suspended solids shall not exceed 80 ppm (standard spec). In Japan, they are limited to 10 ppm.
- The pH of the seawater must be between 7.5 and 8.5.
- Isolated chloride ions (active Cl^-) must be less than 0.05 ppm at the connecting point between the ORV and the piping supplying water.

Submerged Combustion Vaporizers (SCV): The SCV vaporizes LNG contained inside stainless steel tubes in a submerged water bath with a combustion burner. In the baseload terminal SCV, the fuel gas is burned in a large single burner rather than multiple smaller burners because it is more economical and it achieves low NOx and CO levels. The hot flue gases are sparged into a bath of water where the LNG vaporization coils are located.

The SCVs are designed to utilize the low-pressure fuel gas derived from the boil-off gases of the facility and the let-down gas from the send-out gas. They may also use an extracted heavier fuel gas (C_2 plus) from the LNG at the LNG terminal [1].

For the SCV operation, since the thermal capacity of the water bath is high, it is possible to maintain a stable operation even for sudden start-ups/shutdowns and rapid load fluctuations. Thus, they provide great flexibility for quick start-up after shutdowns and the ability to quickly respond to changing demand requirements.

Due to the larger amount of flue gas, there is a concern for NOx and CO_2 emissions for the operation, though a low NOx emission of less than 40 ppm is attainable. The NOx level may be further reduced by using Selective Catalytic Reactor units (SCR) to 5 ppm, but it adds significant cost to the SCV unit, almost doubling the cost of the system.

The bath water becomes acidic as the combustion products are absorbed in it. Alkaline chemicals (e.g. dilute caustic, sodium carbonate and sodium bicarbonate) must be added to the bath water to control pH, and resulting excess combustion water must be neutralized before discharge.

Shell and Tube Vaporizers (STV): The STV and Intermediate Fluid STV type are generally smaller in size and cost competitive compared to an ORV or SCV system. Heat is usually supplied to the LNG vaporizer by a closed circuit with a suitable heat transfer medium. They are mainly used when a suitable heat source is available. Design of these types of vaporizer systems requires a stable LNG flow at design and turndown conditions with provisions to prevent the potential for freeze-up within the vaporizer. These have had only limited application to date.

The design of Double Tube Bundle STV incorporates both a lower and an upper set of tube bundles, and uses an intermediate heat transfer fluid (e.g. propane, isobutane, freon, ammonia) between the LNG (upper tubes) and the seawater or glycol water (lower tubes) inside a single shell. A small shell and tube superheater is required to heat the vapor to 5 °C.

The design used at the US Cove Point terminal uses glycol-water in the lower tube bundle instead of seawater as the heat source. The cooled glycol-water is pumped, circulated and heated by the gas turbine exhaust (waste heat recovery) in another exchanger. The intermediate fluid is isobutane.

In the recent development of STVs using the ambient seawater as the heating medium, they exchange heat directly with seawater. Similar to the issues addressed for ORV units, STVs have additional concerns in corrosion and erosion inside the exchanger when seawater is used as the heating medium. Other issues such as the lowered seawater return temperature and hypo-chlorite in the returned seawater are identical to the ORV system.

The turn-down of seawater flow in the exchanger will be limited in consideration of the possibility of icing when the seawater flow rate is reduced in the heat exchanger.

Combined Heat and Power unit with Submerged Combustion Vaporizer (CHP-SCV): In order to decrease the gas auto-consumption of SCVs, as well as to increase the efficiency and economics of the entire regasification process, the receiving terminal can be modified to use a cogeneration concept that offers energy saving and environmental advantages. This has been implemented at the Zeebrugge LNG Terminal Cogeneration Project [2]. The heart of the CHP facility is a gas turbine type LM6000 that generates 40 MW of electrical power. The hot exhaust gases from the turbine pass through a heat recovery tower and transfer their heat to raise the temperature of a closed hot water circuit. This hot water will then be circulated and injected in the water bath of the vaporizers and transfer its heat to regasify the LNG.

At Zeebrugge the energy conversion of the whole installation amounts to 106.8%. The energy saving is 27.8% considering a 50% efficiency for a modern combined cycle plant and 110% for submerged burners of the LNG vaporizers. In addition, a reduction in CO emission of 27.8 % from the flue gas of the power generation unit is achieved. NOx emissions are reduced by approximately 65% when compared to the reference of separate production of electricity and heat.

After the modifications made to the vaporizers, they have become "hybrid", i.e. they can now be operated in three heating modes. Firstly, with the submerged combustion as per original design; secondly, with the closed circuit of warm water from the CHP plant with the submerged burner off; and thirdly, with both heat sources on. This option will have high-energy efficiency. However it does have some disadvantages:

- It will lower the power plant efficiency.
- The buoyancy of the flue gas will be poor as the flue temperature is lowered to 10 °C. There will be some potential efficiency loss to ensure air emissions do not remain at ground level by heating the exhaust gases.
- The CHP system would require 100 % sparing with SCVs to ensure that in the event that the power plant was not operational, the ability to send out gas would not be impaired.

Other Types - Ambient Air-heated Vaporizers: Ambient air heated vaporizers utilize ambient air in either a natural draft mode or a forced draft mode to vaporize LNG. Such vaporizers are in service for warm climates and with plot space available. They are manufactured by conventional air cooler manufacturers and have been used at India's Petronet LNG Terminal at Dahej, in which the air coolers are manufactured by GEI Hamon Industries.

Environmental Impact Comparison

Open Rack Vaporizer: For a terminal capacity of 7.5 million tonnes per annum LNG sendout, as an example, at least two very large diameter seawater lines, one for inflow and one for outflow, will be required. These lines will be about 2 m in diameter and likely to cause significant impact, during construction, to sensitive / protected marine habitats. This is in addition to the impact on the marine environment due to ongoing operations, which will cause large volumes of marine plankton to be withdrawn, and of cold water to be discharged at some 5 to 12 °C lower than the intake seawater temperature, and possibly containing 0.2 to 2 ppm hypo-chlorite. In addition, the visual impact on the marine and landsite, and impact on terrestrial ecology, may be significant.

The primary benefit of an ORV is that it uses renewable resources and no fossil fuels are burnt and thus there are no carbon dioxide and NOx emissions from the plant, and it does not contribute to global warming.

Submerged Combustion Vaporizer: This option will have a lower energy efficiency than an ORV system in which seawater is pumped to vaporize LNG. It contributes to global warming; air emissions (CO_2, NO_x & CO) are from fuel combustion.

The condensate discharge may have an impact on the marine environment depending on the composition of the discharge. The degree of impact would depend on the location of the outfall point and may also result in minor habitat loss from laying of discharge pipes. A high content of water vapor in stack emissions will likely produce a white vapor plume on cool days.

Waste Heat Utilization: When waste heats are utilized for vaporizing LNG, either by the STV, air cooler type or CHP option, the concerns of the discharges of the flue gas, and/or seawater on the environment are eliminated.

LNG cold has been previously utilized in power plants for gas turbine inlet air chilling. An additional water/glycol or methanol water loop can be provided and an air cooling system for chilling air added. To take advantage of the cooling water in a combined cycle power plant or in an industrial facility if available in the vicinity of the LNG receiving terminal, the cooling water can be utilized for the LNG vaporizers to further improve the power plant or industrial facility performance with minimum additional new equipment.

With the recent development of various new types of vaporizers as described below, the cooling water can be effectively used.

Lower Emission LNG Vaporization Process

In Combined cycle power or industrial plants, cooling water is often used to reject heat from the facilities. The heated water is then cooled down in a cooling tower.

A Lower Emission LNG Vaporization Process is described here which use the waste heat from either a power plant or industrial facilities for LNG vaporization. The process will eliminate fuel requirements, while reducing or eliminating air or water emissions and improving the thermal efficiency of the LNG terminal and plant facilities.

When an LNG Terminal operation is integrated with a Combined Cycle Power Generation Unit by utilizing the cooling water used for condensing the power plant steam turbine exhaust steam for LNG vaporization, the LNG vaporization process will achieve zero emissions.

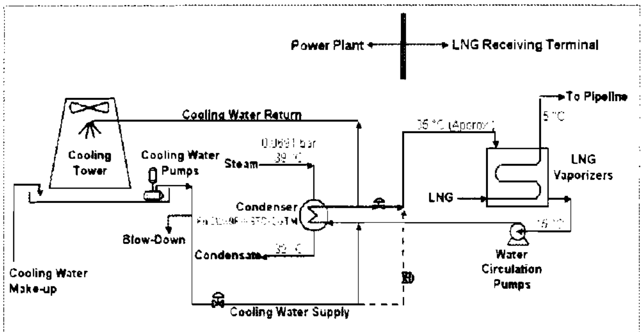

Figure 1 Schematic Process Flow Diagram of Lower Emission LNG Vaporization

As an example (see Figure 1), about 536 million BTU/hr cooling water duty at about 39 °C steam temperature level is required for the GE 9FA Unit Combined Cycle system with 390.8 MW power export. This heat duty can be used to vaporize about 950 million std. ft^3/day, (or 6.9 million tonnes per annum) LNG. About 30,000 gallons/minute of cooling water is needed to pump around the system between the power plant and the LNG terminal based on a 20 °C water temperature drop utilized in the LNG vaporizers.

In this no/lower emission process design, the power plant cooling tower duty is reduced and the power plant efficiency is improved as the steam turbine exhaust steam is condensed at a lower pressure because of using colder cooling water. For example, if the condensing temperature is lowered by 10 °C, the steam turbine power export will be increased by 1.3 MW.

Various types of heat transfer equipment may be used for vaporizing the LNG by utilizing the cooling water.

(1) The LNG vaporizers designed by Chicago Power & Process (CPP) or Kobe Steel (Intermediate Fluid Type LNG Vaporizer). The CPP Vaporizer is a special, patented, shell and tube heat exchanger design, based on established heat transfer theory, experience with low temperature liquids and proven, unique flow path design. A warm fluid source, commonly water, water/glycol mix or sea water, is required for the heat input and will provide natural gas vapor at common distribution temperatures, with no liquid carry-over. The vaporizer can be rapidly started up or shut down, with the capability of operating down to 10% load or less. Capacities range from 4 to 300 million std. ft^3/day. Gas pressure designs extend from 75 to 3500 psig (about 5-240 bar(g)). A sketch of a typical CPP vaporizer is shown in Figure 2.

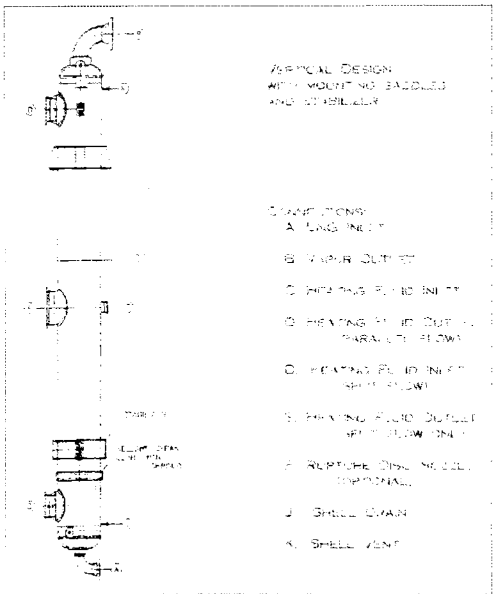

Figure 2 CPP Vaporizer / Typical Elevation (Courtesy - Chicago Power & Process)

(2) The Reli-Vap vaporizer designed by Wheaton Process Systems, which is a modified shell and tube heat exchanger design, shown in Figure 3. The vaporizer consists of tube side heat transfer circuits positioned within a trough-like heating medium containment structure. The heating medium, which can be water, glycol water or other intermediate fluid, flows through the vaporizer in a completely cross flow serpentine arrangement. Plenums are used to provide the cross flow heating medium passages. The full cross flow design provides higher and more uniform heat transfer rates. The Reli-Vap provides an economical solution to both open loop and closed loop vaporizer applications.

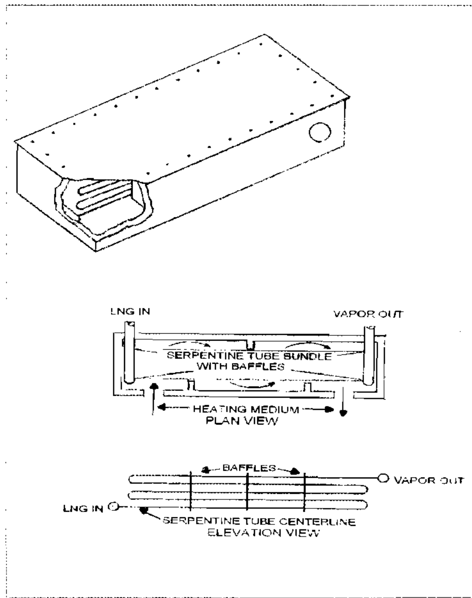

Figure 3 RELI - VAP Vaporizer Sketch (Courtesy - Wheaton)

(3) A modified SCV system similar to the Combined Heat and Power Unit described earlier (CHP-SCV). Instead of using the scrubbed warm water from the gas turbine exhaust gas stack, it would use the cooling water from condensing the steam turbine exhaust steam as the heat medium.

The concept of Lower Emission LNG Vaporization Process can also be applied to ORV operation. If the seawater temperature is lower and/or a higher gas send-out temperature is required, seawater could flow to the power plant unit first then to the ORVs to make the operation practical and useful.

Conclusions

Both ORV and SCV units produce some impacts on the environment. The proposed water circulation by utilizing the cooling tower water for LNG vaporization also furnishes synergy between Power Plant or industrial facilities and the LNG Receiving Terminal. The process scheme described produces no or lower emissions, and therefore significantly reduces the environmental impact of the facility. ■

Acknowledgement

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LNG Regasification Vessel – The First Offshore LNG Facility

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Abstract

Active studies have been made on the offshore LNG receiving terminal by many people around world. Especially in USA, many actual LNG receiving terminal projects are under progress and some are under engineering and construction stages. Among the candidates, the LNG Regassification Vessel (LNG RV) would be the first offshore LNG receiving facility. The successful operation of the LNG RV would accelerate the similar application by proving technical and commercial grounds. The LNG RV adopts onboard regasification (regas) and turret facilities in addition to the conventional LNG carrier. The regas process is mainly composed of the LNG feed pumps, high pressure LNG pumps, vaporizers, and send-out equipment, which are similar to those of a land-based LNG receiving terminal. The regas capacity of the vessel is approximately 500 mmscfd. The first LNG RV has been delivered to her ship owner in January 2005 after successful completion of the gas and regas trial. The first commercial operation will start later March, 2005. So, at the time of this paper presentation, the operation of the first cargo would have completed in the Gulf of Mexico. The experiences gained from the first LNG RV implementation could be a step stone for the future offshore LNG terminal technologies.

Introduction

Considering most of the feed gas for the LNG is produced in offshore and most LNG is imported via sea, it might be natural that many people in the LNG industry would consider offshore LNG facilities as alternatives for the land-based ones. However, despite of rapid expansion of the LNG industry and the abundance of the offshore LNG facility concepts, no physical offshore LNG facility is existent so far. Two major sectors of the offshore LNG facility would be LNG FSRU (Floating Storage and Regasification Unit) and LNG FPSO (Floating Production Storage and Offloading). Both the LNG FSRU and FPSO concepts are well-known and now approaching implementation stages. In the environment, the successful completion of the LNG RV, the first offshore LNG facility, would be an important achievement in the LNG technology. The purpose of this paper is to introduce the LNG RV status to those who are interested in and have contributed to the offshore LNG technology.

LNG RV (Regasification Vessel)

LNG RV is a vessel with combined functions of the conventional LNG carrier, offshore mooring turret and regasification (regas) facilities. As the vessel has onboard regas facility, the regasified natural gas (NG) can be connected directly to a commercial pipeline trunk. Therefore the process does not need any land-based LNG receiving and regas facilities. The basic concept of the LNG RV is shown in Fig 2. Though the LNG RV concept is unique, the technologies used in LNG RV are based on proven conventional ones. The long operation records of the ocean-going LNG vessels have proved the reliabilities of the onboard equipment and the LNG containment system. The similar onboard turret systems have been used for many years for crude oil shuttle tanker applications. The HP (high pressure) LNG pumps have been widely used in the land-based LNG receiving terminals, and the shell and tube type vaporizers also have several references in land-based facilities. Therefore the reliabilities of each of the components of the LNG RV system have been verified from the early stage. The normal regas capacity of the LNG RV is 500 mmscfd. With the capacity, the full cargo of 138,000 m^3 LNG can be regasified and delivered in less than 6 days. In certain situations, the maximum throughput can be increased to 690 mmscfd. All required tests for the LNG RV including the sea trial, submerged buoy mating, gas trial, and regas trial have been successfully completed in the shipyard stage before the delivery of the vessel to her ship owner.

The overall offshore regasification facility operation concept of the LNG RV has been introduced as "Energy Bridge". The typical Energy Bridge deepwater port facility is composed of 1

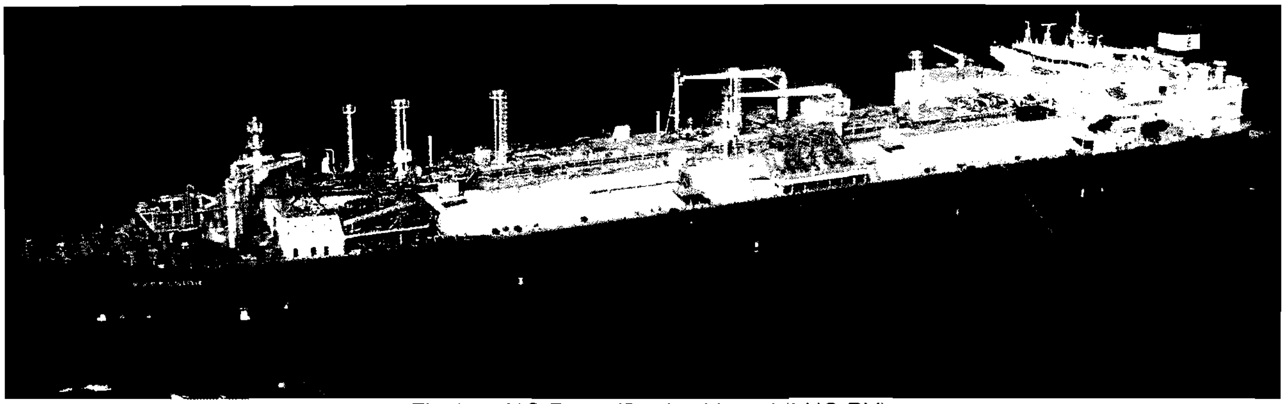

Fig 1 - LNG Regasification Vessel (LNG RV)

or 2 submerged buoys and subsea facility in one location. Hence, the LNG RV may be used as an independent unit by boosting the natural gas (NG) supply to the existing network or as a fleet of multiple LNG RV's so that uninterrupted offshore regasification operation could be made. The second LNG RV is under construction and it will be delivered in the end of April 2005. As gaining actual offshore regaficication references, the LNG RV and the Energy Bridge concept may bring unavoidable comparisons with other type of offshore and onshore LNG receiving terminals in technical and economic aspects. We believe the LNG RV would have competitiveness in proven operation reference, project budget and schedule, and operational flexibility.

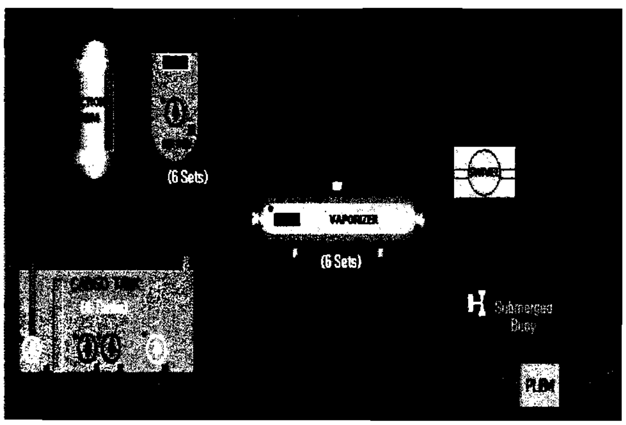

Fig 2 - LNG RV Process Concept

Brief Features of LNG RV

	System	Contents
Onboard (Conventional)	Principal Dimensions	LxBxD : 277 m x 43.4 m x 26 m 138.000 M^3, 19.3 knot
	Cargo Containment Pump Tower	Membrane type – GTT No. 96 Reinforced for the partial loading operation Reinforced pump tower
	Cargo Tank	4 Tanks
	Propulsion	Boiler and Steam Turbine
	Cargo Handling	Cargo pumps, HD, LD Compressors, Heaters
Onboard (Regas)	Regas	Location: forward part Vaporizer/HP LNG Pump: 6 units (3 in port and 3 in starboard, each 100 mmscfd) Regas capacity : 500 mmscfd (5 running and 1 stand by) Metering system Heating medium : Sea Water
	Turret	Internal turret Traction Winch with Heave Compensator Swivel for HP NG Send Out
	HP Manifold	Additional Send Out Facility (1 Port, 1 Starboard)
	Heating Water	3 Heating Water Pumps : 3 x 5000 m3/hr (3 x 50%) 3 HW Steam Heaters : 3 x 50%
	Side Thrusters	2 Bow thrusters :2 x 1500 KW 1 Stern thruster : 1 x 2000 KW
	Positioning System	Positioning system with acoustic transceiver and DGPS
	Power Generation	1 Diesel and 3 turbo generators : 4 x approx. 3700 KW (3 running 1 stand by)
Subsea (External from LNG RV)	Submerged Buoy	Installed approximately 25 meters below the sea surface Moored by the 8 leg spread mooring lines Water depth : 35 m and above
	PLEM	Connected via flexible riser Shut down valves and transmitters
	Subsea Pipe	Connected to the NG main trunk line

Table 1 - Brief Features of LNG RV

Description of LNG RV

LNG in Offshore

Whereas LNG basics and process are well known in the LNG production and receiving terminal industry, it may rarely have been introduced in the OTC so far. The distinctive characteristics of the LNG would be the low temperature (- 162 °C), low density (s.g. approx 0.45) and relatively higher flammability compared to crude oil. Though the LNG is contained in well-insulated cargo tanks, natural boil off gas (BOG) is generated from the tanks (typically approximately 0.125% per day). The BOG (approx. 4-2 ton per hour depending on the tank level) is normally used as fuel for the ship propulsion or electric power generation. As the LNG is not electrically conductive, the electric motors for the cargo pumps can be directly immerged in the LNG. LNG cargo handling piping system, material selection, equipment, and operation modes are well defined and standardized in the LNG industry. The LNG and the LNG BOG are environmentally very clean substances compared with the normal natural gas as the impurities such as the sulfur contents are completely removed during the LNG reliquefaction process.

Ship Systems

Hull General. The hull construction is similar to the conventional LNG carriers except some strengthening of the hull structure. Therefore, proven design concepts could be preserved.

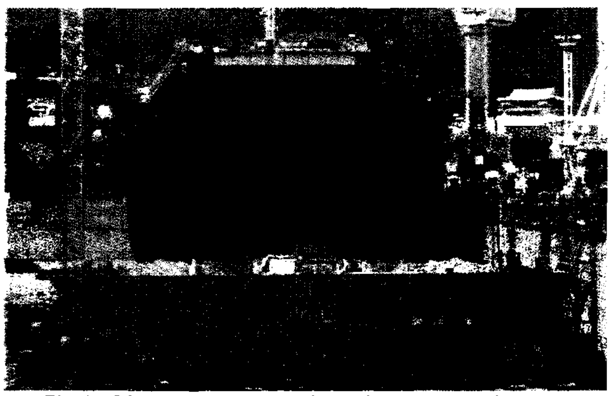

Fig 3 - LNG RV Cargo Tank During Construction Stage

Seakeeping. The seakeeping ability during the regas operation has been extensively studied by theoretical analysis and actual model tests. The model tests in various operation scenarios and extreme weather conditions have been carried out. The results show that the LNG RV can withstand 100 year wave during hurricane (approximately 11 meters significant wave height) in mooring condition in Gulf of Mexico. It also showed the capability of LNG RV mating operation in severe winter storm condition in the region. However for additional safety, the LNG RV can be evacuated during the hurricane, and the mating operation wave height criteria may be reduced. Nevertheless, the total availability of the LNG RV would be very high, and it would be comparable or exceeds those of typical offshore platforms and land-based LNG receiving terminals in the region.

Fig 4 - LNG RV Seakeeping Model Test

Cargo Containment. The LNG cargo sloshing in the cargo tank is an important consideration in the design of the LNG carriers. The LNG RV requires unrestricted cargo filling level due to the inherent regas operation. Many theoretical and experiment studies on the sloshing have been made in the early design stage. The containment system design was reinforced based on a sailing North Atlantic sea condition. For the purpose, the complete insulations were reinforced except the flat bottom of the cargo tanks. Therefore there is no filling limit in the operation of the regas system. The construction of the LNG cargo containment system is well established and virtually became mass production system rather than custom made works through a series of the construction in shipyard.

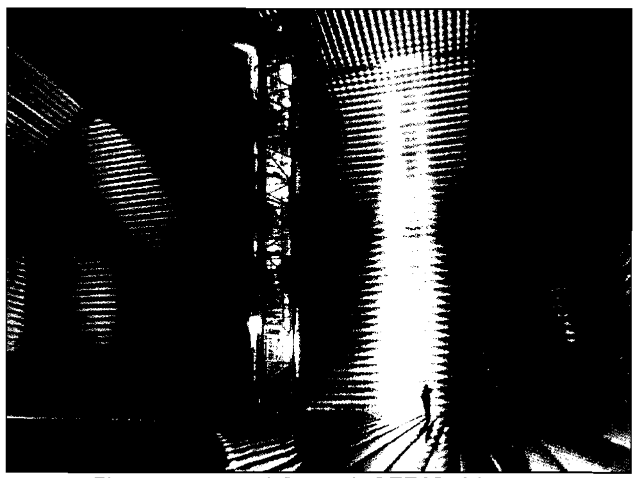

Fig 5 - Cargo Tank Internal (GTT No 96 type)

Propulsion. The main boiler and steam turbine are used for the propulsion of the LNG RV for the normal voyages from and to the LNG production terminals. The boiler capacity was significantly increased to accommodate the steam consumption for the heating water system when the sea water temperature in the specific operation site is low (below 14.7 °C).

Cargo Handling System. The same concept of the conventional LNG carrier cargo handling system has been maintained. Therefore, the LNG unloading as well as the loading operation can be done the same way as the conventional LNC carrier. To supply the LNG to the regas system from the cargo tank, 3 additional feeding pumps have been installed in the tanks in addition to the conventional cargo and spray pumps.

Positioning System. The submerged buoy location is usually known, and the vessel can approach to the mating site with the aid of DGPS (differential global positioning system). But in the vicinity of the submerged buoy and during the buoy connection operation, the acoustic positioning system is also used for the confirmation of the buoy location and as a self-reliant sensing device. The submerged buoy has 6 transponders, so the location of the submerged buoy can be detected by onboard acoustic transceiver. To approach to the mating site and to assist keeping the buoy center within tolerable range, a vessel positioning system has to be provided. The LNG RV is equipped with 2 bow thrusters, 1 stern thruster, and steam turbine driven propulsion system. The positioning system collects the buoy location, wind, thruster, turbine, and rudder information from the external sensors. Based on the information, the vessel thruster and turbine system outputs are allocated and the corresponding forces are exerted to keep or to approach the predefined position. For the LNG RV mating application, a dedicated system called maneuvering aid and positioning system (MAPS) has been developed and successfully implemented.

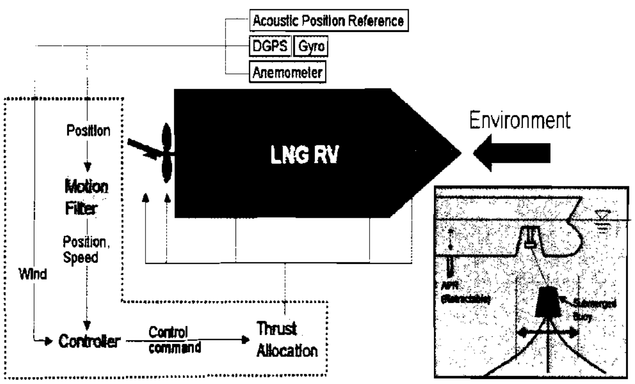

Fig 6 - MAPS Conceptual Diagram

Control and Safety System. DCS (Distributed Control System) based centralized shipboard control system has been applied for the LNG RV. Therefore, overall consistency in the control, safety, and alarm management could be maintained. In addition to the normal control system, an independent ESD (Emergency Shut Down) system has been provided for the shutdown of the critical valves and equipment in emergency situations. The ESD system is composed of the conventional LNG carrier and the LNG RV modes. The conventional LNG carrier mode is exactly the same as the ESD requirements for the conventional vessel, and the LNG RV mode ESD system has the safety features for the regas, turret and PLEM systems. Hence the integrated safety for onboard regas system, turret system, submerged buoy system, and the subsea PLEM could be made. The normal control system also has been extended to the submerged buoy and the PLEM systems. Hence seamless operation for the regas NG line connection, disconnection, pressurization, depressurization, blow down operation could be achieved by the centralized onboard control system. The LNG RV regas system calls for advanced control algorithms for the multiple HP LNG pump and vaporizer line ups and interlocks, throughput capacity, various cascade operations, and variable pressure operation up to the consumer network's pressure and various restrictions from each equipment and systems. The complicated LNG RV control requirements could be implemented without much difficulty due to the inherent features and flexibility of the DCS based onboard control system.

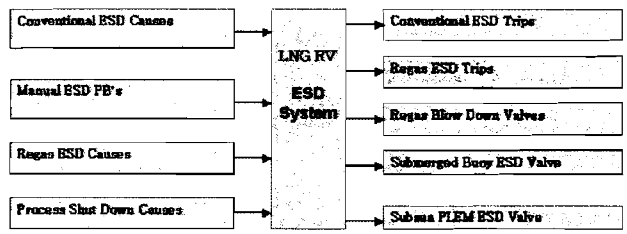

Fig 7 - LNG RV ESD Concept

Offloading Systems

Turret System. The LNG RV is moored to the submerged buoy, and weathervanes to minimize the drag and ship motion during the regas operation. The vessel motion in the mooring position is normally small compared with that of the unrestricted ocean-going case. The swivel system provides HP NG connection between the weathervaning LNG RV and the fixed submerged

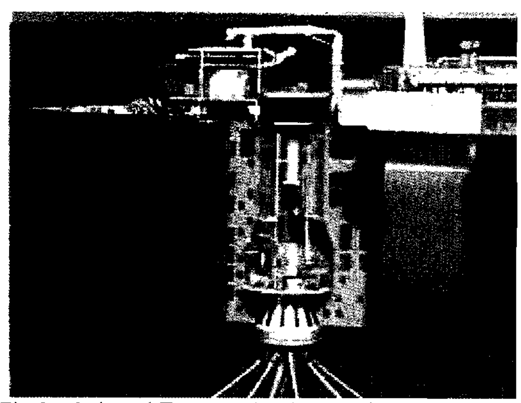

Fig 8 - Onboard Turret and Submerged Buoy Systems

buoy. The normal buoy connection and disconnection take approximately 2-3 hours and 1-2 hours respectively. However in emergency situation, the buoy can be disconnected very quickly, approximately 15 minutes, and the LNG RV evacuated to a safe location. The vaporized NG from the regas system is connected to the swivel mechanism and submerged buoy through the onboard flexible riser. The turret system includes submerged buoy locking mechanism, rope guider, traction winch, swivel handling system, flexible riser, CCTV(Closed Circuit TV), hydraulic, and control system.

Subsea System. The subsea system is composed of submerged buoy, subsea riser, PLEM, and subsea pipe. The buoy is located approximately 25 meters below the sea surface. The buoy is moored by the 8 leg spread mooring lines. The typical water depth in the proposed GOM is 95 meters. The submerged buoy for the LNG RV may be installed in any convenient location, provided the water depth is over approximately 35 meters. Shut down valves and transmitters are located in the PLEM and operated by the onboard LNG RV control system. For GOM application, an unmanned metering platform for the 2 different commercial pipeline interconnections has been installed.

Regasification Systems

Process. The LNG stored in the cargo tank is fed to the suction drum. The HP pumps take the LNG from the suction drum and send to the HP vaporizers. The LNG is vaporized in the vaporizers and fed to the consumer's NG network through the turret system or the midship HP manifold.

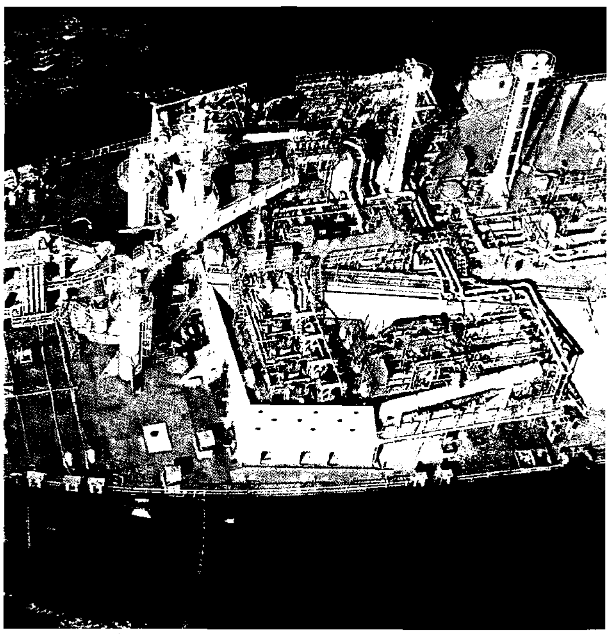

Fig 9 - LNG RV Forward Part - Regas Area

Feed Pump. The in-tank submerged pump supplies the LNG to the suction drum. Main cargo pump, spray pumps also can be used for the feeding of the LNG to the regas system, initial preparation, and cargo transfer to other tanks if specific operation is necessary.

Suction Drum. The suction drum is composed of the LNG liquid and the vapor parts. The liquid level and the pressure are controlled by the central control system (integrated automation system, IAS). The suction drum is used for the buffers of HP pump LNG suction and the vent and depressurizing of the regas system. The BOG generated during the regas operation and the excessive gas during the depressurization is sent back to the cargo tank through the suction drum. The suction drum is important part of the regas operation for the stable LNG supply to the regas system and the BOG gas treatment.

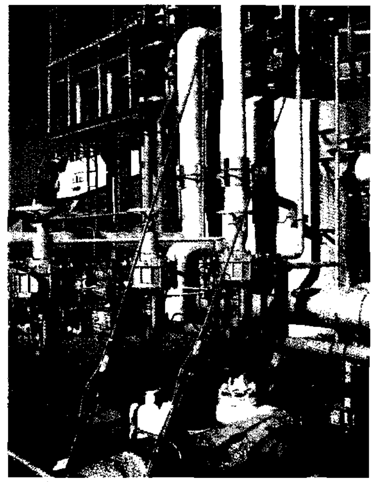

Fig 10 - Suction Drum Overview

HP LNG Pump. The HP LNG pump is 13 stage centrifugal pump, and supplies the LNG to the vaporizers. The pump is operated at high pressure. Therefore, special attentions on the possible LNG leak and piping route due to the cold temperature have to be paid. The operation pressure of the HP LNG pump is typically 100 bar. In order to guarantee the stable operation of the HP LNG pump, LNG in the suction pots of the HP pump should be maintained at the sub-cooled condition for the corresponding operation suction pressure. During the normal operation of the HP LNG pump, some vapor is generated from the pump pot and should be properly vented for stable pump operation. For the initial pressurizing of the regas system, 2 small HP pumps (1 in port 1 and in starboard) have been prepared.

Vaporizer. The vaporizer is operated in the supercritical pressure region. Hence, the heat transfer mechanism and design would be different from those of the conventional heat exchangers. The high temperature differences, high pressure, and sea water heating medium call for special attention on the heat transfer and mechanical design, material selection, and fabrication. The shell and tube type vaporizers have been adopted to reduce any adverse effect due to the vessel motion in the floating environment. The LNG RV vaporizers are very compact compared with other land-based vaporizers.

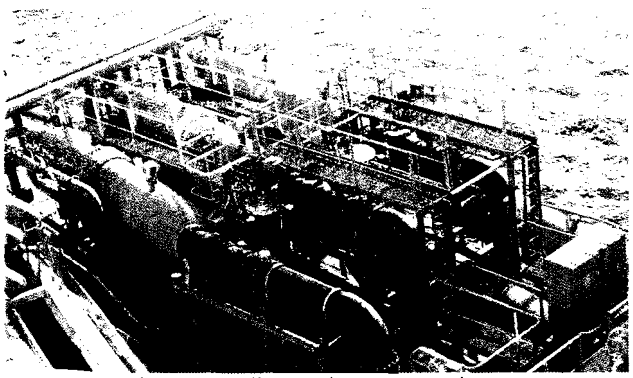

Fig 11 - Shell and tube type vaporizers
: 3 in port and 3 in starboard side

Metering Unit. Metering unit is installed to measure the send out NG amount. The metering system is equipped with the ultrasonic type flow measurement, gas analyzer, dedicated flow computer, and signal repeats to shipboard central control system (IAS).

Send Out. The vaporized NG is sent to the subsea PLEM and the subsea pipe through the swivel mechanism. In addition to the vaporized gas discharge through the turret, the LNG RV has facility for the side discharge through the HP manifold system when the vessel is suitably berthed to a mooring quay. The send out pressure control valve controls the required regas system pressure regardless of the consumer network pressure. Whereas the vaporizer should be operated above critical pressure for good performance, the large pressure drop across the send out pressure control valve would bring the adverse effect to the delivered NG by reducing the NG temperature and increasing the velocity. Therefore advanced control for the variable pressure operation has been adopted. The pressure control should be well coordinated with the main flow capacity controller.

Heating Water Pump. Sea water is used for the heating medium of the LNG vaporization. The heating water is drawn from the conventional ballast system, boosted by the booster pumps located in the forward area, and delivered to the vaporizers. According to the sea water temperature, the system can be either open or closed loop. In closed loop, the sea water or fresh water is heated in the sea water heaters by the steam from the onboard main boilers when the sea water temperature is low. In that case the steam generated from the existing main boilers is de-superheated and supplied to the sea water heater through the long low pressure steam line along the enclosed passage way. The quality of the sea water in offshore is normally very good compared with that of the land-based LNG receiving terminal. Therefore complicated sea water treatment system as the land - based terminal is not required in the LNG RV environment.

Utilities. For the power generation of the LNG RV, 3 steam turbine driven generators and 1 diesel generator are installed. In normal operation condition, 3 units are running and 1 is standby. As the LNG RV uses large electric loads, additional high voltage regas switchboard room has been arranged beneath the forward mooring deck of the vessel.

Protection Against LNG Spillage and HP NG Leak. Special attentions have been paid against the spillage of the LNG and HP NG leak from the early design stage. The high pressure LNG lines between the HP pumps and the vaporizers have been intentionally made short to reduce the risk of HP LNG spillage. The whole LNG handling parts of the regas area are protected by the stainless steel drip tray and pan. Hence any spillage of the LNG can be protected by the shield plate and safely collected to the drip tray. Flange parts of HP NG lines have been also protected by the shield devices for possible leaks or jet flames. A deluge system is provided to the regas area, and the sea water is flowing to the protection shield and drip pan continuously during the regas operation. Water spray and gas detection system are provided in the regas area.

Environment. The LNG itself is not prone to pollution, and in LNG RV, no methane gas is vented to the atmosphere except in an emergency. BOG gas from the cargo tanks and the regas system is safely burned in onboard boilers. The generated steam is used mainly for the electric power generation, and the excessive steam is dumped to the condenser. The emission level by the boiler combustion either with BOG or fuel oil is far lower than those of most ocean going vessels. The LNG RV discharges cold and hot heat at the same time to the sea environment from the vaporizers and from the steam condenser. However, the total balance of cold and hot heat discharge from the LNG RV would be far less than that of the conventional LNG carrier. Though the LNG RV is operated in a limited zone during the regas operation, the environmental effects in the offshore would be very small.

Regasification Operation Procedure

Preparation for the turret system. When the vessel approaches the submerged buoy site, MAPS system is used for the locating the submerged buoy and position keeping of the LNG RV. A messenger line is lowered to the onboard turret opening and connected to a messenger line of the submerged buoy. The submerged buoy is hoisted by the onboard traction winch, and connected to the onboard turret system. The onboard flexible riser with swivel mechanism is connected to the top of the submerged buoy.

Cool down. The regas system is cooled down usually before the arrival of the regas site. The cool down procedure is similar to that of conventional LNG carrier cargo handling system. Cooling down is important for the stable operation of HP pumps.

Pressurization. After the system is sufficiently cooled down, the regas system is pressurized. The pressuring is usually done by the small HP pump. When the regas and the NG network system pressure become almost the same pressure, the regas system is ready for the send out operation.

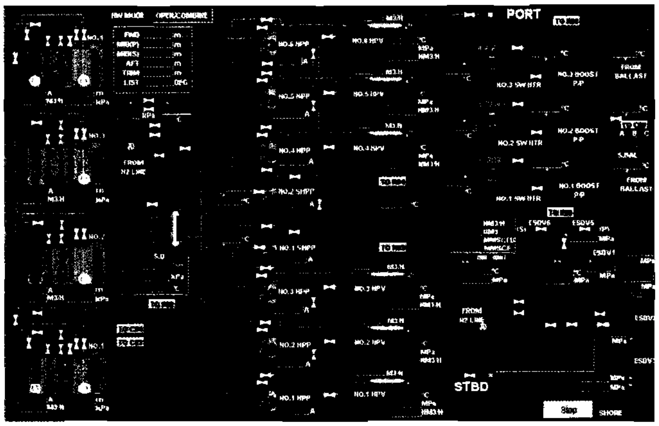

Fig 12 – LNG RV Regas Overview Graphics

Send out. The HP LNG pumps are used for the sending out the LNG to the vaporizers. Before starting the vaporizers, the heating water system should be operated. The heating water is supplied by the onboard ballast and booster pumps. The vaporized NG passes the metering unit for the measurement of the NG volume and calorific value. The vaporized NG is fed to the NG pipeline network. During the start up of the send out operation, the PLEM pressure and valve open and closed status is monitored and appropriate control is made by the LNG RV control system.

Depressurization. Once the regas operation is completed, the delivery valve is closed and isolated from the NG trunk line. The HP NG line, the turret and subsea risers are depressurized for the buoy disconnection. The depressurized NG is returned to the cargo tank through the suction drum. The appropriate pressure depressurizing sequence and the control are predefined and incorporated in the control system and the operation manual.

Buoy disconnection. When the riser system is depressurized, the LNG RV can be disconnected from the submerged buoy with normal procedure. For emergency situation, the emergency buoy disconnection operation mode is provided.

Drain / Inerting. The remaining LNG is drained when the regas operation is completed, and inerting of the regas system can be made if necessary.

Design and Construction

Engineering. From the early stage of the engineering, many basic concepts and ideas have been derived from joint works of shipyard, ship owner, and charterer. The intensive joint studies and active discussions were very effective in the determination of the regas design. A Korean engineering company, who has many experiences in the land-based LNG receiving terminal designs, has worked together in the early design stage. During the regas system detail design, we could get advise from land-based LNG receiving terminal engineers and operators. Though we had assistances from outsides directly or indirectly, we believe most of the engineering and development could be made by the shipyard, ship owner, and charterer's efforts. To verify the regas operation in the shipboard environment, a test facility has been constructed by the charterer and the full-scale vaporizer and HP pump operation performance test (1 HP LNG pump and 1 vaporizer) on a hydraulic moving platform had been carried out before finalizing the LNG RV design details.

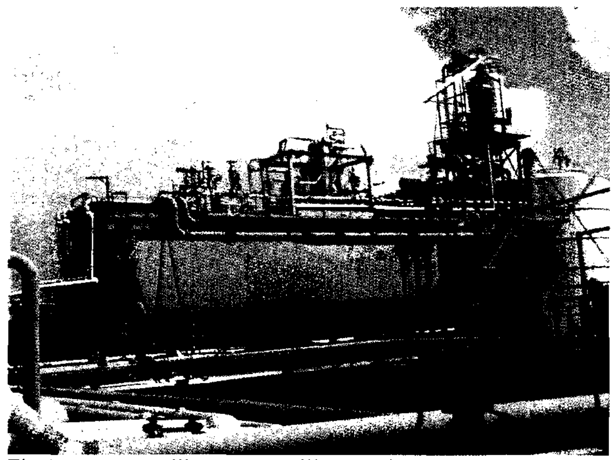
Fig 13 - Test Facility : Trussville, AL, USA (September 2003)

Construction. The construction of the LNG RV went relatively well though there were some inexperienced tasks in high pressure LNG and NG lines, and turret system. From the contract to the delivery of the vessel, it took 2 year and 8 months. This period includes the basic design and system development. We expect the similar vessel can be constructed several months less than the first one.

Commissioning/Sea/Gas/Regas Trials

As most of the tests have been done in shipyard quay stage, there were no significant problems during the sea, gas, and regas trials. The regas system has been tested beforehand using liquid nitrogen during the shipyard dock trials. The mating of the submerged buoy was also carried out by using specially designed submerged dummy buoy with the same acoustic transponders during the sea trial. Therefore most of the turret operation could be verified with the same procedures as the actual site operating condition. The extensive regas system operations based on the actual send out scenarios and important control functions have been verified by using the actual LNG during the regas trial. During the regas trial prior to delivery, the high pressure pump and the vaporizer have been operated one by one, not 5 units at the same time, due to the generated NG buffering capacity limitation in the cargo tanks.

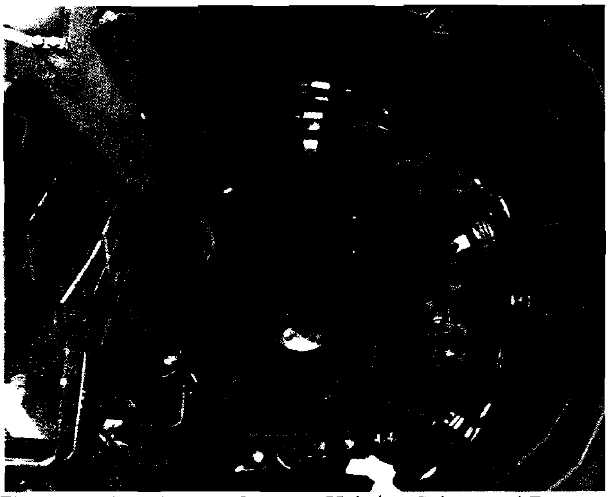

Fig 14 - Onboard Turret System : Hoisting Submerged Buoy

Fig 15 – Regas Operation During Regas Trial (December 2004)

Operator's Training

MAPS Simulator. The LNG RV mating with the submerged buoy, approaching, position keeping, and the steam turbine and thruster operation are much different from the convention operation of a vessel. Therefore, a dedicated training simulator system (MAPS) for the familiarization of the system has been developed.

Regas Simulator. The regas system operation in the LNG RV environment was quite unique and contained many inexperienced works on the HP liquid LNG and gas handling. This regas system operation also called for careful preparation

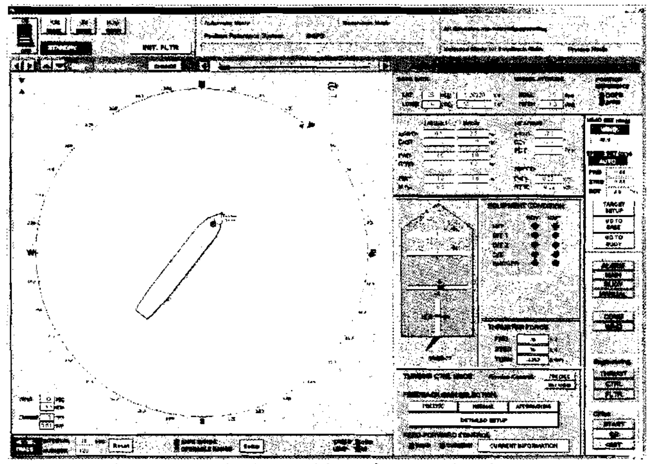

Fig 16 – Typical Graphics of Maps simulator

works of cool down, pressurization, and depressurization. Many equipment were cross related with different operation modes. Therefore the thorough understanding of the process and familiarization of the operation was important to the overall operation efficiency and the safety of the LNG RV. An advanced simulator system with control logics, control loops, and mathematical models of the whole regas system has been developed and utilized for the training of the onboard operators.

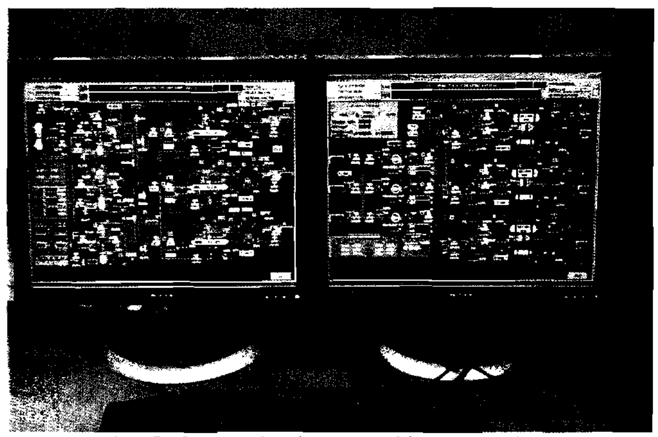

Fig 17 - Regas Simulator Graphics : example

Summaries and Conclusions

- The LNG RV has been successfully constructed and delivered to her ship owner for commercial operation.
- LNG RV is the first offshore LNG facility. However, it is based on the proven technologies in the shipbuilding and offshore industries.
- LNG RV would have competitiveness in LNG regasification field by taking advantage of the large

building industry.

- volume standard construction practices in the ship-building industry.
- The successful construction of the LNG RV would contribute the safe and stable supply of the clean energy.

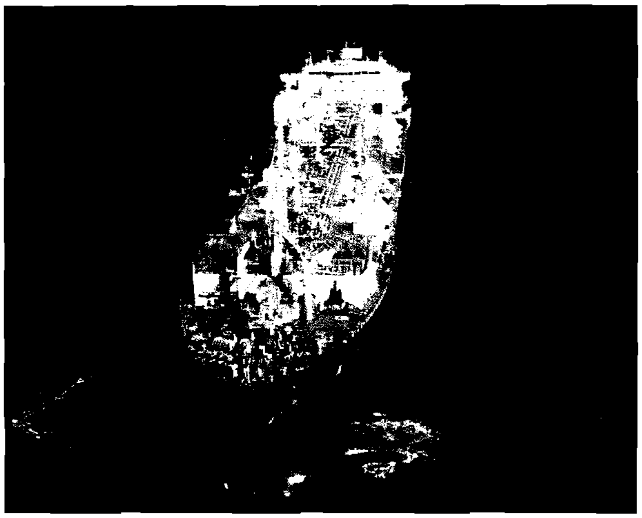

Fig 18 - LNG RV : The First Offshore LNG Facility

Nomenclature

BOG	: Boil Off Gas
DCS	: Distributed Control System
GOM	: Gulf Of Mexico
HP	: High Pressure
IAS	: Integrated Automation System
LNG RV	: LNG Regasification Vessel
MAPS	: Maneuvering Aids and Positioning System
MMSCFD	: Million Standard Cubic Feet per Day
NG	: Natural Gas
PLEM	: Pipe Line End Manifold
Regas	: Regasification

Acknowledgements

We believe that the successful deployment of the LNG RV have been contributed by many companies and the people who had worked directly or indirectly for this project, and turret system, vaporizer, HP pump, and control system vendors, who supplied their equipment for the LNG RV. We believe that the joint effort spirit as a team from Daewoo Shipbuilding and Marine Engineering, Exmar, and Excelerate Energy has been the origin of the project success. We also believe our project team is heavily indebted to those who have pioneered the concepts of the offshore LNG facilities. We heartily respect their efforts and passions for the new technology.

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Section 2
Detailed Description of the Project and Alternatives

2. Detailed Description of the Project and Alternatives

The Secretary proposes to act on the Applicant's Deepwater Port License Application to construct, own, and operate a deepwater port for importation of LNG and send-out of natural gas. The Port, proposed to be located 35.4 km (22 mi) northeast of Boston, Massachusetts, in a water depth of approximately 76.2 m (250 ft), would consist of two submersible unloading buoys, 4.0 km (2.5 mi) of flowline between the two buoys, and 17.5 km (10.9 mi) of natural gas transmission pipeline. Equipment aboard vessels built specifically to transport and revaporize LNG using on-board equipment would regasify LNG, and a pipeline from the port would deliver the natural gas to the HubLine in Massachusetts Bay. This section identifies alternatives that meet the purpose of and need for the Project, alternatives that have been eliminated from detailed analysis because they do not meet the purpose of and need for the Project, and the No Action Alternative. The section concludes with a detailed description of the Applicant's proposal.

2.1 Alternatives

NEPA requires that any Federal agency proposing a major action (as defined under NEPA) must consider reasonable alternatives to the Proposed Action. Evaluation of alternatives assists in avoiding unnecessary impacts by analyzing reasonable options to achieve the underlying purpose that the Applicant might or might not have considered. This analysis of alternatives broadens the scope of options that might be available to reduce or avoid impacts associated with the action as proposed by the Applicant. The Secretary may approve or deny an application[13] for a license under the DWPA. In approving a license application, the Secretary may impose enforceable conditions as part of the license. Consistent with NEPA, in determining the provisions of the license, the Secretary may also consider alternative means to construct and operate a deepwater port. The NEPA environmental analysis is one of the nine factors the Secretary must consider in making a final determination (33 U.S.C. 1503c). Alternatives for a LNG deepwater port may extend to matters such as its specific location, methods of construction, technologies for storing and regasifying LNG, and specific routes for transmission of product. Considering alternatives helps to avoid unnecessary impacts and allows analysis of reasonable ways to achieve the stated purpose.

To warrant detailed evaluation by the USCG and MARAD, an alternative must be reasonable and meet the Secretary's purpose and need (see **Section 1.2**). Alternatives concerning location, construction, and operation of a deepwater port for receipt and transfer of LNG must meet essential technical, engineering, and economic threshold requirements to ensure that a proposed action is environmentally sound, economically viable, responsive to vessel and facility operating needs, and compliant with governing standards. Screening criteria are used to determine the feasibility of alternatives. The Secretary has identified potential alternatives to the Project. The following discussion identifies alternatives found to be reasonable, alternatives found not to be reasonable, and, for the latter, the basis for such finding. Alternatives considered but found not to be reasonable are not evaluated in detail in this EIS/EIR.

2.1.1 Alternatives for Analysis

2.1.1.1 Offshore vs. Onshore LNG Alternatives

Congress has passed statutes that distribute responsibility for the development of LNG facilities in the United States across different agencies within the Federal government. For offshore LNG facilities,

[13] For the application at hand, the No Action Alternative and denial of the license are considered to be the same.

the USCG and MARAD jointly share responsibility for evaluating and processing applications submitted under the DWPA. For onshore facilities, the responsibility lies within the FERC under the Natural Gas Act. Proposed onshore and offshore facilities are projects independent of each other (i.e., they are not mutually exclusive); therefore they are not considered to be alternatives to each other. Several onshore LNG facilities exist or are being proposed that target the New England market. Onshore facilities are discussed under the No Action Alternative, since they could be developed regardless of the outcome of any proposed DWPA application. The NEG Project is discussed in **Section 6**, Cumulative and Other Impacts, as a foreseeable action. Both the Neptune and NEG projects could be licensed by the secretary, they are also not considered to be alternatives to each other. Finally, this EIS/EIR does not address how many LNG facilities would be needed to meet the growing demand on New England because that decision would ultimately be based on market conditions.

2.1.1.2 Offshore Port Design Alternatives

There are five basic deepwater port concept designs that have been developed by the industry and are currently considered commercially available for use as an offshore LNG import port: gravity-based structure (GBS); platform-based unit; floating storage and regasification unit (FSRU); special purpose vessels (SPVs) that transport and vaporize LNG onboard, such as the SRV proposed for this Project; and special purpose floating platforms that house vaporization equipment and are capable of docking with the LNGCs. All five port concepts include use of subsea natural gas pipelines to transport regasified LNG from the port to the existing onshore pipeline system.

Although there is some adaptability of design in each of the five concepts, there are inherent features of each that are most compatible with certain environmental conditions and that lend themselves to specific business models. A site was not eliminated solely because a single preselected type of port design was not suitable for conditions present at that site. Likewise, a design was not eliminated prior to considering whether that design would be the most suitable for the preferred site.

- *Gravity-Based Structure Design.* GBS consists of a large concrete structure that contains integrated storage tanks and sits on the seafloor. The GBS would be built at an onshore graving dock using well-proven construction methods and then floated, towed to the site, and installed on the seabed. This port concept has been commonly and successfully used in the offshore oil and gas industry for decades. LNG could be offloaded from conventional LNGCs, placed in storage tanks, and then vaporized for delivery as natural gas to the onshore market via an undersea pipeline. Given the expense associated with constructing and operating a GBS, it appears that these facilities are only economically feasible for projects with relatively large LNG storage (e.g., 250,000 to 330,000 m^3) and natural gas send-out volumes (e.g., 800 to 2,000 MMscfd). The Port Pelican and Gulf Landing Projects have been approved to use facilities of this design in the Gulf of Mexico. The Compass Port and Beacon Port Projects have proposed to use GBS designs.
- *Platform-Based Unit.* The platform-based unit design would consist of constructing or converting an existing offshore platform or platforms with docking facilities and LNG unloading arms, storage, and vaporization equipment. Because these platforms are or would be anchored using fixed-tower structures, they could be located in a broader range of water depths than a GBS. Similar to the GBS design, LNG could be unloaded from conventional LNGCs, vaporized at the platform, and sent as natural gas to the onshore market via an undersea pipeline. Depending on the specific design, the use of an offshore platform might not include significant offshore storage of LNG. Crystal Energy LLC has proposed using an existing platform as a terminal to import LNG into California, and Freeport-McMoRan

Energy LLC has proposed to modify a series of existing connected platforms about 26 km (16 mi) off the coast of southeastern Louisiana to use as a deepwater LNG terminal.

- *Floating Storage and Regasification Unit.* An FSRU is a purpose-built floating shiplike vessel without a propulsion system, based on LNGC technology and components of floating production, storage, and offloading (FPSO) systems, which are widely used in the offshore oil and gas production industry. LNG storage tanks with at least twice the capacity of a typical LNGC would be integrated within the hull, and regasification and unloading equipment would be on deck. These units would be permanently anchored offshore where conventional LNGCs could dock next to and unload LNG to the FSRU. The FSRU would be connected to an external turret, which would allow high-pressure gas to be sent out through a riser to the subsea pipeline. While the FSRU could be spread-moored (i.e., on a constant heading), a weathervaning turret-mooring would most likely be used, unless a very sheltered location was available. Companies are currently proposing to use this design to import natural gas to markets in California (Cabrillo Port) and New York (Broadwater Energy).
- *Special Purpose Vessel.* This concept is significantly different from the other three technologies insofar as it does not involve any permanent storage or regasification facility. Instead, a fleet of SPVs, such as the SRVs proposed for this Project, each containing onboard LNG vaporization equipment, would be built. The vessels would be moored at the offshore port site with a permanently installed single-point or submerged-turret unloading buoy. After mooring, LNG would be vaporized onboard the vessel and discharged via the unloading buoy and a flexible riser into the subsea pipeline. Because the LNG would be vaporized with the SRV's onboard equipment, no permanent fixed or floating storage or vaporization facilities would be required. Unlike standard LNGCs, which offload LNG in 18 hours or less, SRVs offload natural gas (i.e., regasified LNG) and inject it into a subsea natural gas pipeline at standard pipeline pressures. As a result, this process can take several days to discharge a full cargo of LNG, and continuous off-loading operations are essential to minimize fluctuations in the throughput of natural gas. Excelerate Energy's Gulf Gateway Project has begun operation in the Gulf of Mexico using this approach, and Excelerate Energy has proposed the Northeast Gateway (NEG) Project in Massachusetts Bay using the SPV technology.
- *Special Purpose Floating Platform.* This concept is essentially a hybrid of the special submerged buoy concept and the platform-based unit. A floating platform (FP) is anchored in place by an anchoring system similar to the anchors used for submerged unloading buoys. The FP is designed to dock with conventional LNGCs. Vaporization equipment is housed on the platform, and a small support platform constructed nearby houses personnel facilities and support structures for the floating platform. No LNG storage would be provided by this design. The Bienville Offshore Energy Project using this concept has been proposed by TORP Technologies for construction in the Gulf of Mexico.

Evaluation of LNG Port Concept Design Alternatives

The evaluation of the LNG port concept alternatives was based on several environmental factors, technical considerations, and commercial objectives.

Environmental Effects

Installation of a GBS would generally result in a much greater loss of benthic and fish habitat than would the other concept designs (more than 10 acres). The other port designs have a relatively small bottom footprint and, therefore, would potentially result in significantly less of an effect on fish and marine communities. Because of significant material needs, the GBS option is generally only economically viable when located in water depths less than 25.9 m (85 ft). A GBS design also can involve significant coastal impacts (e.g., wetland loss, dredging) because it might require construction of a very large graving dock and sufficient nearshore water depths for floating the GBS to deeper water. In addition, because of its maximum depth limitations, use of a GBS would impact sensitive shallow water habitats and fisheries. It also could result in the facility being sited in nearshore areas where the majority of recreational boating and fishing activity takes place and where it creates potential safety and aesthetic concerns. Furthermore, GBS, as well as platform-based facilities, are permanent fixed structures that stand taller than the floating designs, resulting in greater visual effects or being visible further from shore.

On the other hand, GBS and platform-based units would each serve as artificial reefs, providing a significant amount of hard substrate for the development of new encrusting and fouling communities. As has been demonstrated by other permanent offshore oil and gas structures, such facilities have a potential to support significant and diverse fish and shellfish communities.

Water Depth

Due to the requirements for an appropriate water depth for safe navigation of the LNG vessels and considerations of their construction cost, GBS ports are generally limited to water depths between 13.7 and 25.9 m (45 and 85 ft). Other types of stationary structures, such as platform-based units, can be located in deeper water. FSRUs, SRVs, and FPs require a permanently installed anchoring system and sufficient water depth (generally greater than 60.1 m [200 ft]) to accommodate mooring lines and a flexible riser connection between the unit and the subsea pipeline. FPs also require an additional support platform.

Substrate

GBS structures must be located in areas where the seafloor is relatively level, lacking in geologic hazards, and with satisfactory substrate characteristics to support the structure's foundation and weight. Platform-based and FP units also require avoiding areas with geologic hazards. The FSRU and SRV concept designs have more flexibility on seafloor conditions because alternative anchoring methods are available to accommodate different types of substrate.

Reliability

Platform-based units that are designed for continuous supply of natural gas must have sufficient storage capacity on the platforms to allow continuous vaporization while LNGCs are transiting to and from the platforms and present more operating limitations than GBS structures or floating systems under severe weather conditions. This would require additional platforms or require the platforms to be larger than required to house the vaporization equipment and related supporting facilities. The Main Pass Energy Hub™ Deepwater Port Project has been proposed as a platform-based LNG terminal that incorporates storage into its design. This requires two special purpose platforms for storage tanks, increasing the footprint and costs of the project. It also would use a "Soft Berth" system of floating dolphins to moor the LNGCs. This allows an LNGC to dock in seas up to 2.0 m (6.6 ft) and winds up to 25 knots, as noted in **Table 2.1-1**. The FSRU would remain on location for longer periods of time (10 to 20 years or more) and would not leave the site for hurricanes or other severe weather such as northeasters. On the other hand, because an SRV would be equipped for traditional side-by-side unloading, diversion of SRVs to other ports also would be possible under extreme weather conditions. The FP design provides for docking with a wide range of existing and planned conventional LNGCs. FPs have weather-related characteristics similar to SRVs. Model tests have demonstrated capabilities to dock with LNGCs and to continue offloading operations in seas up to 4.5 m (14 ft) (TORP LNG 2006a, 2006b).

The FSRU option would result in greater downtime due to prevailing weather conditions at the planned deepwater port. The side-by-side unloading from FSRUs should be limited to 2.0-m (6.6-ft) significant wave heights for approximately 24 hours for each scheduled offloading from the LNGCs to the FSRU. On the other hand, an SRV can be moored to the specially designed unloading buoys in 3.5-m (11.5-ft) significant wave heights. **Table 2.1-1** compares the approximate percentages of time that wave heights greater than 2.0 m (6.6 ft) and 3.5 m (11.5 ft) occur in the project area.

Table 2.1-2 shows that the FSRU option is more sensitive to weather conditions than the SRV option, because of increased risks for interruption of the delivery of natural gas to New England. The sensitivity is based on weather effects on mooring and unloading of SRVs, as well as the FSRUs processing operations due to LNG sloshing in tanks and other motion-related effects on fluid mechanics. This risk is further aggravated by the fact that the greatest weather downtime would occur between January and April, which is the period of greatest demand for natural gas.

An FSRU requires equipment for tying an LNGC alongside it, as well as the unloading arms and other ancillary equipment to unload the LNG from the carrier. Conventional LNGCs would be used for transporting and delivering LNG to the FSRU. Although an SRV and unloading buoy system could be more costly than a conventional LNGC due to the required vaporization and buoy mating systems, the total capital cost of a FSRU system that would meet this Project's supply conditions would likely be larger, mainly due to the increased costs to accommodate floating storage needs. Because the Applicant has proposed to build SPVs, use of an FP system with the SRVs would require unnecessary redundancy and significantly increase costs without increasing capacity or improving reliability.

Table 2.1-1. Percentage of Occurrence of Wave Heights (meters)

Wave Heights	Jan – Apr	May – Aug	Sep – Dec	Annual Average
> 3.5 m	1 %	0 %	1 %	1 %
< 3.5 m	99 %	100 %	99 %	99 %
> 2.0 m	13 %	2 %	9 %	9 %
< 2.0 m	87 %	98 %	91 %	92 %

Table 2.1-2. Equivalent Days of Downtime

Operations	Significant Wave Heights	Jan – Apr	May – Aug	Sep – Dec	Annual Average
SRV weather downtime	> 3.5	2	0	1	3
SRV weather uptime	< 3.5	120	122	120	362
FSRU weather downtime	> 2.9	15	2	11	28
FSRU weather uptime	< 2.0	106	120	111	337

Selection of LNG Port Concept Design Alternative

A platform-based unit would be likely to have more frequent interruptions of gas supply due to more operational limitations during heavy weather conditions. A platform-based unit would require additional platforms to be installed to contain sufficient LNG storage to unload the entire cargo from an LNGC. Therefore, either several platforms would be required, with attendant environmental impacts, or regasification would have to be performed directly as LNG is unloaded from the moored LNGC. If a vessel is unable to moor alongside the fixed structure due to high winds and wave conditions, the throughput could be interrupted. Essentially, a platform-based system has more limited operational ability to moor, connect, and unload LNG compared to an SRV during bad weather conditions. Thus, the level of reliability and continuous throughput required for the commercial viability of the Project might not be achieved using the platform-based system.

Although a GBS port would have high reliability for continuous delivery of supply, it has several significant disadvantages because it must be sited in shallow waters, where it presents a source of impact to areas of high marine productivity, potential conflict with nearshore fisheries, proximity to nearshore recreational boating and fishing areas, and a permanent visual obstruction on the horizon. These shortcomings, coupled with high capital and construction costs, make the GBS design less preferable. GBS port designs were determined to be less practical for the Project because large storage and send-out volumes are not required, and the design could lead to potentially significant impacts on shallow water marine habitats. Therefore, the GBS design is not carried forward for detailed review, and sites suitable for GBS port designs were not considered in the analysis of alternative locations.

The FSRU has nearly the same level of environmental impacts as the SRV but the limitation to offloading availability during severe weather conditions due to mooring and unloading arm operational and safety limitations was considered to be significant for the Project location. Furthermore, severe weather conditions require additional engineering design efforts to mitigate the adverse operational effects induced by cryogenic liquid sloshing in the LNG storage tanks, which could reduce the ability to meet the in-service date. The FSRU, due to its storage tanks and its purpose-built, site-specific design and associated cost, is economically suited for large send-outs and long-distance shipping. Most significantly, no alternatives for use of an FSRU were found to provide environmental impacts that would be appreciably lower than the SRV design. Therefore, the FSRU design is not carried forward for detailed review.

The FP design would provide capabilities similar to the SRVs. The existing FP design can only support an open-loop shell-and-tube vaporizer system design. Since there are extended periods of the year during which water temperatures in Massachusetts Bay will not support vaporization using seawater without supplemental energy input (such as burning a portion of the vaporized natural gas), the FP design is not technically feasible for the Project area. Since a support platform would also be required, the FP design would have higher environmental impacts than the SRV design. Therefore the FP design is not carried forward for detailed review.

The SRV design has a small environmental footprint and can be located in deeper water, farther from shore. The SRVs can operate in more extreme sea conditions, and therefore provide greater reliability of service. The design can support the Applicant's proposed gas send-out rates without additional storage or control platforms. Therefore, the SRV design is the only Port design carried forward for detailed review.

2.1.1.3 Alternative Offshore Port Locations

There are a number of possible locations off the U.S. coast that would be suitable for siting an LNG port. A company proposing to construct and operate an offshore port would have identified a market that it believes would provide the economic incentives that support licensing and construction costs. Therefore, alternative offshore port locations must be evaluated in light of the target market for the natural gas. Since the Project is intended to supply natural gas to the Massachusetts market and surrounding areas, only locations that meet these fundamental criteria would be considered.

Based on the regional energy analysis discussed in **Section 1.2.3**, it is reasonable to use a phased process to identify and evaluate potential locations for an offshore LNG import port considering the opportunities and constraints posed by each of the deepwater port concept designs available. The alternatives analysis used a screening and site-selection process that began with the entire central New England coastal region and progressively narrowed the geographic range of locations where it would be reasonable and feasible to site an offshore LNG facility. The three steps of this siting process are summarized below; the analyses are then discussed in the subsequent sections.

- ***Phase 1, Regional Site Screening.*** The first phase of evaluation of alternative locations was a screening of the central New England region, including Massachusetts Bay and adjacent areas of New Hampshire and Rhode Island, to select a feasible area or areas within the region for siting a deepwater port LNG import facility. Feasible areas were defined based upon the following criteria: suitable proximity to market, proximity to existing offshore gas transmission pipelines, required operational water depths, meteorological and ocean (metocean) conditions, and proximity to populated areas. The primary screening process compared the suitability of various deepwater port concept designs at alternative areas to eliminate those areas where it would not be reasonable or feasible to locate an LNG deepwater port facility. One subregion (Massachusetts Bay) was selected for further analysis.
- ***Phase 2, Suitable Area Analysis.*** The secondary screening process compared the advantages and disadvantages of the alternative locations within the feasible area identified in Phase 1 to eliminate those locations where it is not reasonable or feasible to locate an LNG deepwater port facility. The selection criteria included sufficient facility footprint area, proximity to existing pipelines, distance to regional commercial shipping lanes, and proximity to or potential effects on marine protected areas and important marine resources. Three sectors (the Northwest Sector, the Northeast Sector, and the South Sector) were identified for further evaluation.
- ***Phase 3, Site Specific Analysis.*** During Phase 3, specific alternative deepwater port sites were identified within the three sectors identified in Phase 2. The third and final phase of the evaluation process consisted of developing specific evaluation criteria to allow for a more detailed examination and comparison of potential alternative locations within the sectors to select a proposed port facility location. These criteria consist of site attributes that affect the environmental, economic, safety, and operational suitability of the Project.

In identifying a potential site for a project, USCG guidelines (Title 33 CFR Section 148.720) for siting LNG deepwater port terminals must be considered. The guidelines indicate that an appropriate site for a deepwater port

- Optimizes location to prevent or minimize detrimental environmental effects
- Minimizes the space needed for safe and efficient operation
- Locates offshore components in areas with stable seabottom characteristics
- Locates onshore components where stable foundations can be developed
- Minimizes the potential for interference with its safe operation from existing offshore structures and activities
- Minimizes the danger posed to safe navigation by surrounding water depths and currents
- Avoids extensive dredging or removal of natural obstacles such as reefs

- Minimizes the danger to the port, its components, and tankers calling at the port from storms, earthquakes, or other natural hazards
- Maximizes the permitted use of existing work areas, facilities, and access routes
- Minimizes the environmental impact of temporary work areas, facilities, and access routes
- Maximizes the distance between the port and its components and critical habitats including commercial and sport fisheries, threatened or endangered species habitats, wetlands, floodplains, coastal resources, marine management areas, and EFH
- Minimizes the displacement of existing or potential mining, oil or gas production, or transportation uses
- Takes advantage of areas already allocated for similar use, without overusing such areas
- Avoids permanent interference with natural processes or features that are important to natural currents and wave patterns
- Avoids dredging in areas where sediments contain high levels of heavy metals, biocides, oil, or other pollutants or hazardous materials and in areas designated as wetlands or other protected coastal resources

Phase 1, Regional Site Screening

This analysis considered various scenarios for siting a LNG deepwater import port at a location that would allow access to the Applicant's target market. The first phase (regional site screening) was to determine the general region within the central New England coast with the greatest potential to meet all of the environmental, regulatory, technical, operability, and commercial requirements. The selected region would also need to meet the DWPA requirements as specified in Title 33 CFR Section 148.720 (listed above).

A primary challenge of the regional site-screening process was to identify sites that balance the primary environmental, economic, operational, and safety criteria, all of which are directly or indirectly related to the site's distance from shore. Sites in inshore waters tend to have the best metocean conditions and would be closest to the existing pipeline network; however, inshore areas are generally more heavily used for recreational activities and commercial fishing than areas more distant from shore. Sites located farther offshore also tend to lessen perceived aesthetic effects and safety concerns, but increase the overall impacts on marine resources due to construction of a longer pipeline. The screening criteria to select the most reasonable and feasible alternative area in the central New England region to locate the Port are discussed as follows.

Proximity to Market

Because Massachusetts accounts for half of all natural gas consumption among the New England states, the Applicant's target market was primarily Massachusetts and associated metropolitan areas. Therefore, deepwater port location alternatives within the central New England region include three offshore coastal areas: Southern Massachusetts/Rhode Island, Massachusetts Bay, and Northern Massachusetts/New Hampshire.

Proximity to Offshore Pipelines

Because the Port would be offshore, a principal screening criterion is to interconnect with an existing offshore pipeline. This criterion was selected to avoid the potentially significant nearshore, shoreline, and onshore environmental impacts associated with constructing an interconnecting pipeline through shallow coastal waters, across fragile shoreline areas and the associated habitats, and inland through shore areas. As shown in **Figure 1.2-2**, the only currently existing offshore natural gas pipeline in the region is the HubLine. The Islander East and Iroquois ELI extensions to Long Island have not received regulatory approvals. Therefore, sites that did not provide access to the HubLine were not considered further.

Metocean Conditions

A primary goal in siting any LNG port, either offshore or onshore, is to maximize the duration of port availability and minimize interruptions of operations. Existing long-term metocean data from NOAA's National Data Buoy Center (NDBC) were examined from various data buoys within the region to determine frequency of occurrence of wave heights and wind velocities that could prevent or interfere with docking/mooring and unloading operations. Areas with higher frequencies of metocean conditions that exceeded acceptable operational thresholds were eliminated from consideration.

Suitable Water Depth

Suitable water depths vary with the type of deepwater concept design. Floating moorings typically involve a buoy with associated anchoring systems to connect a pipeline to the SRV. The floating mooring and delivery systems for use on SRV offloading buoys have a recommended minimum operational depth of 60.1 m (200 ft), which is required to accommodate the flexible riser between the buoy and the subsea pipeline. Therefore, only locations with a minimum depth of 60.1 m (200 ft) were considered suitable for the proposed LNG deepwater port facility.

Proximity to Populated Areas

One of the primary purposes for locating an LNG port offshore is to remove facilities from the proximity of populated areas. The benefits of this remoteness are two-fold: public concerns about the consequences of an accidental LNG release would be diminished, and the visual obstruction posed by large SRVs would be significantly reduced or eliminated.

Phase 1 Conclusion

Based upon the regional site-screening evaluation, the only area within the region where it would be reasonable and feasible to locate an SRV facility would be within the Massachusetts Bay area. Advantages of the Massachusetts Bay coast include

- Proximity to the major market (Massachusetts)
- Proximity to an existing offshore pipeline, which could eliminate the need to construct a connecting pipeline through sensitive coastal resources
- Offshore areas with protected waters that provide suitable metocean conditions needed to ensure continuity of operation and reliability of supply
- Acceptable distance from population centers.

Although there are areas north of Cape Anne and south of Cape Cod that could be considered, the resultant extensions of the pipeline through coastal waters and sensitive habitat areas would add significant impacts that would not be required if suitable sites in Massachusetts Bay are available. The areas north of Cape Anne and south of Cape Cod would also have metocean conditions that were more severe than those inside Massachusetts Bay.

Phase 2, Massachusetts Bay Suitable Area Analysis

The secondary screening process compared the advantages and disadvantages of the alternative locations within the feasible area identified in Phase 1 to eliminate those locations where it is not reasonable or feasible to locate an LNG deepwater port facility. The selection criteria included sufficient facility footprint area, proximity to existing pipelines, distance to regional commercial shipping lanes, and proximity to or potential effects on marine protected areas and important marine resources. Three sectors within the Massachusetts Bay area that might serve as general locations for a deepwater port were identified for further evaluation. These are referred to as the Northwest Sector, Northeast Sector, and South Sector. These sectors are shown in **Figure 2.1-1**.

The Applicant's selection criteria regarding potentially suitable areas are listed below and the stepwise progression is shown in **Figure 2.1-2**. Independent evaluation of these site-selection criteria has concluded that these criteria are reasonable.

Step 1, Water Depth Constraint

As discussed in **Section 2.1.1.1**, operation of a buoy system requires water depths greater than 60.1 m (200 ft). First, areas that had sufficient water depth were identified.

Step 2, Shipping Lane Constraint

Interference of LNG deepwater port operations with designated shipping fairways is prohibited. Therefore, only locations within the Massachusetts Bay area outside the boundaries of the Boston Traffic Separation Scheme (TSS), including precautionary areas, were deemed acceptable as potential areas for the proposed LNG deepwater port facility. The evaluation also considered potential interference with traffic to and from the designated dredge disposal sites in the vicinity of the port facility and proposed modifications or additions to the Boston TSS. NMFS has issued a Notice of Intent to prepare an EIS to analyze the potential impacts of the above regulations and other nonregulatory measures (70 FR 36121-36124). The Boston TSS is the set of ingress and egress corridors and the associated separation lane that is established and recommended by the International Maritime Organization (IMO) for large vessels transiting to and from Boston Harbor. One nonregulatory measure being considered is a shift of the east-west portion of the Boston TSS approximately 12 degrees to the north, and the corresponding lengthening of the north-south portions of the TSS (**Figure 2.1-1**). To accommodate these changes, each of the east-west lanes of the TSS would also be narrowed from 3.2 to 2.4 km (2.0 to 1.5 mi) in width. The USCG has proposed this reconfigured TSS to the IMO for approval and implementation.

Potential sites must be in areas that are accessible by SRVs from commercial shipping lanes in the area. The port must also be a sufficient distance from shipping traffic to minimize the risk of vessel collisions while the SRVs are stationed at the unloading buoy.

Step 3, Marine Protected Area Constraint

Several state and Federal marine sanctuaries occur in Massachusetts Bay, including the Gerry E. Studds-Stellwagen Bank National Marine Sanctuary (SBNMS), the South Essex Ocean Sanctuary, and the North Shore Ocean Sanctuary. Although the Federal and state regulations governing the Marine and Ocean Sanctuaries allow for multiple uses of the sanctuaries, construction of the Port within the sanctuaries would be unnecessarily disruptive to the resources that the sanctuaries had been established to protect.

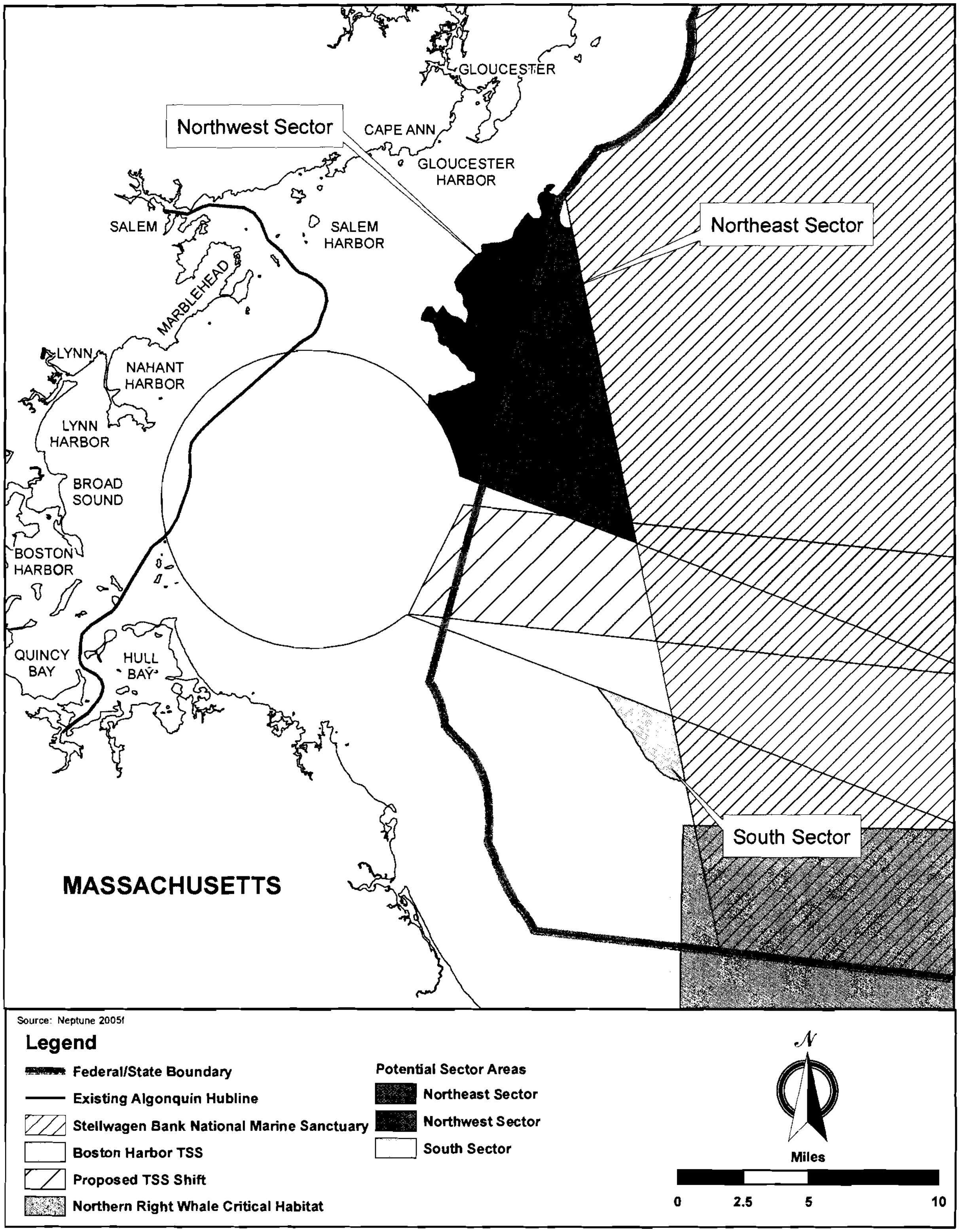
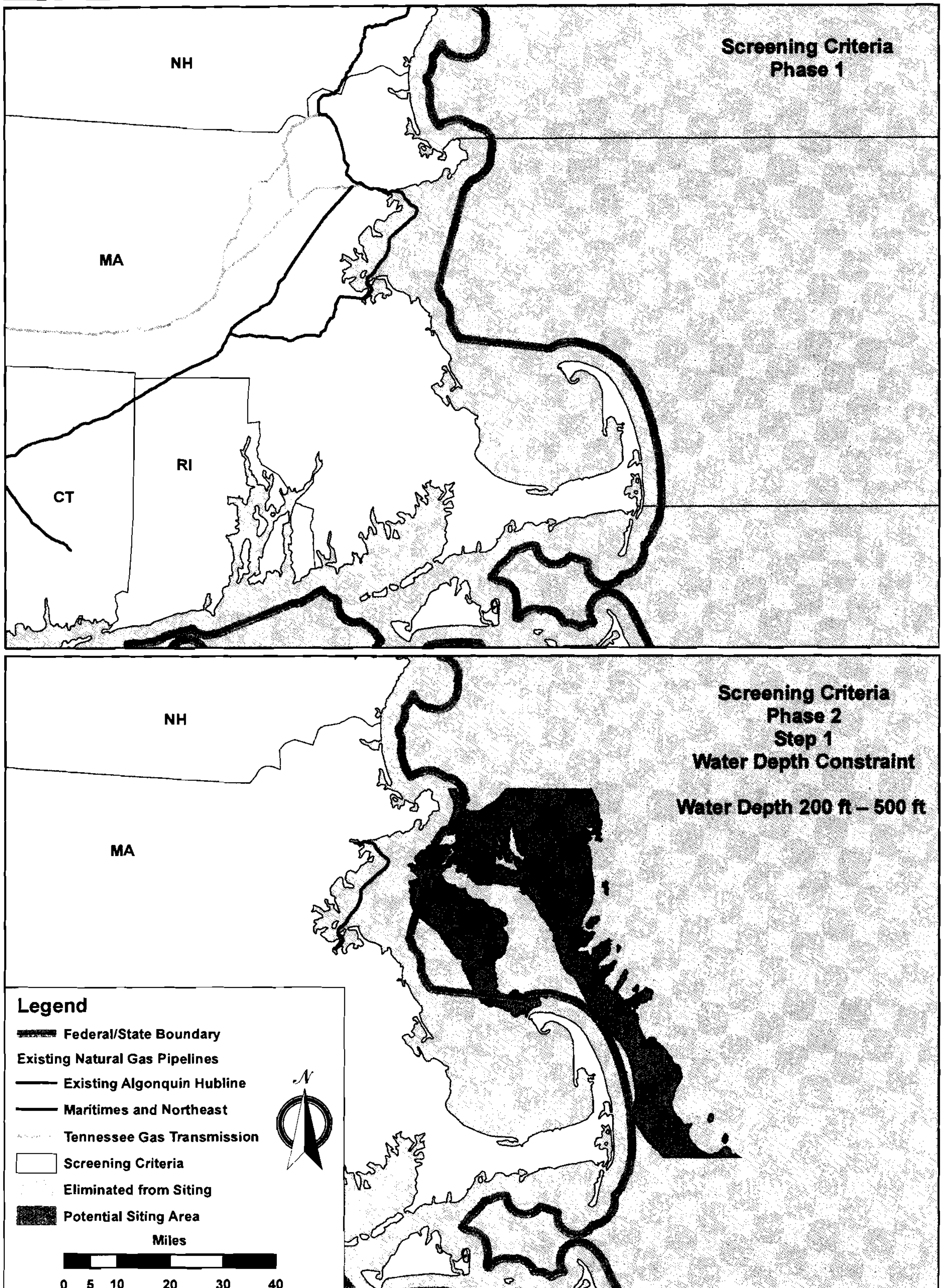
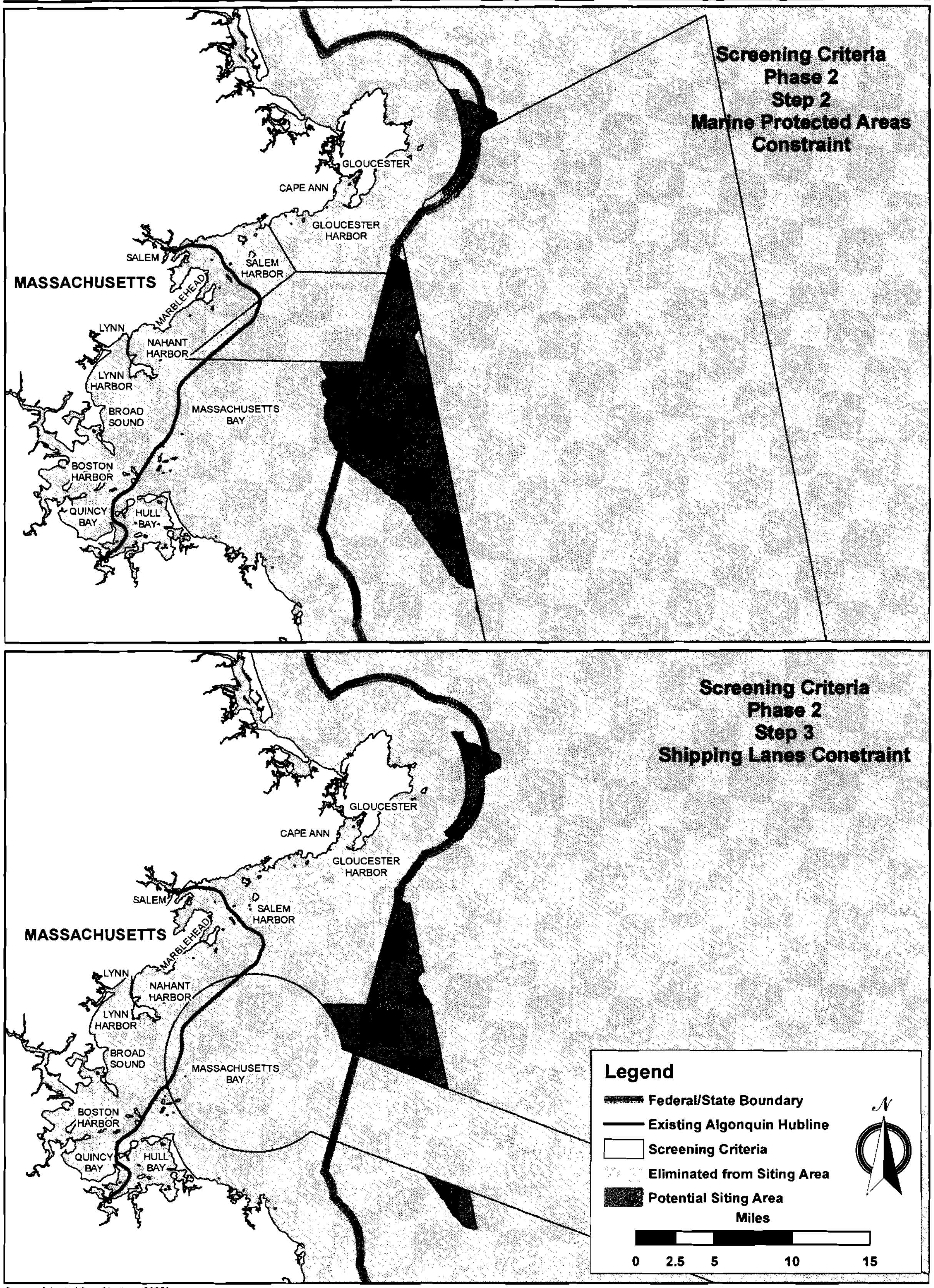


Figure 2.1-1. Potential Sectors within Massachusetts Bay for Siting the Neptune Project



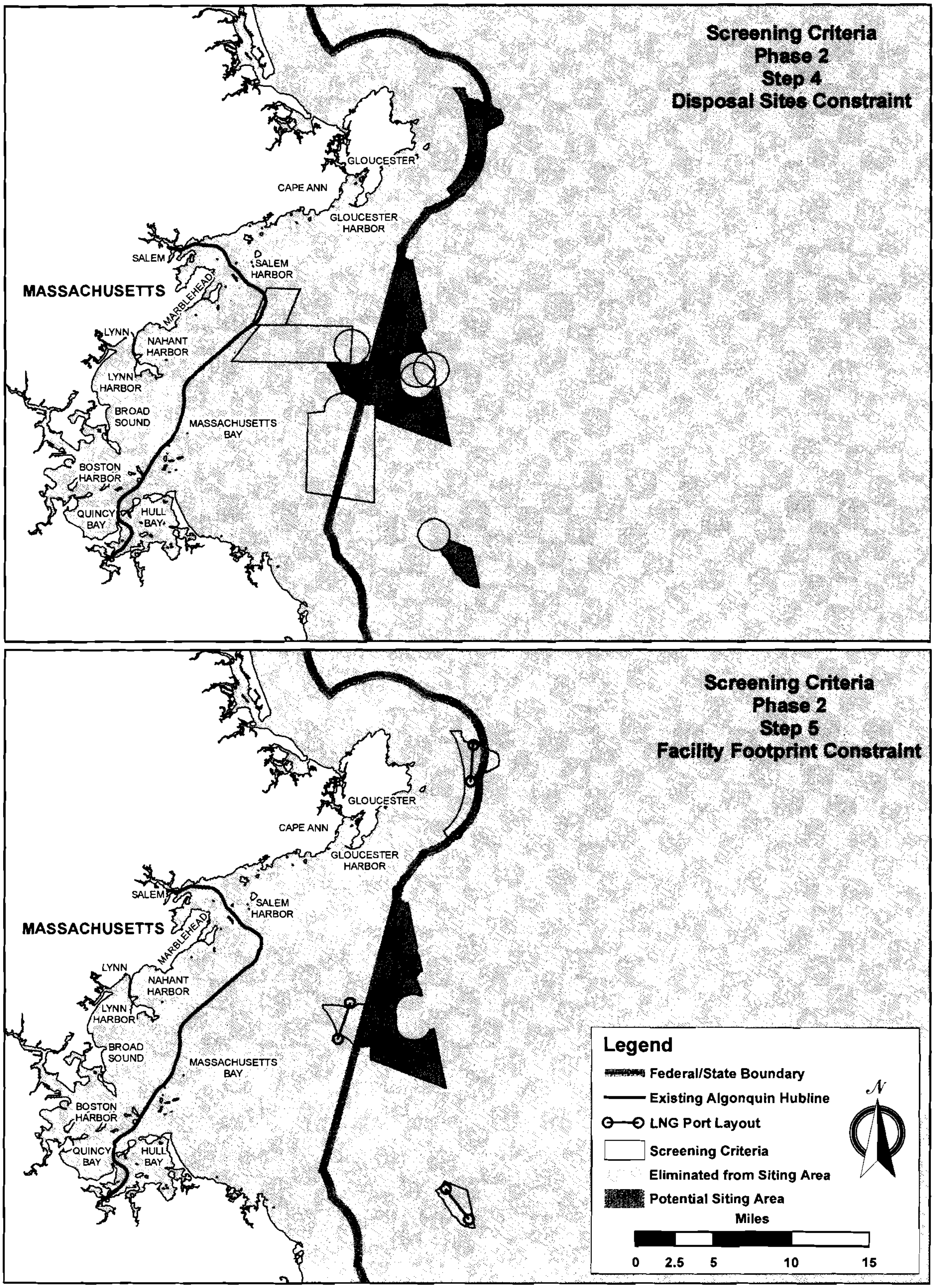
Source: Adapted from Neptune 2005f

Figure 2.1-2. Regional Site Screening Process for the Neptune Project



Source: Adapted from Neptune 2005f

Figure 2.1-2. Regional Site Screening Process for the Neptune Project (continued)



Source: Adapted from Neptune 2005f

Figure 2.1-2. Regional Site Screening Process for the Neptune Project (continued)

Step 4, Disposal Site Constraint

Construction of the deepwater port would not be possible within the location of the Massachusetts Bay Disposal Site (MBDS), the Industrial Waste Site, and the Interim Dredged Material Disposal Site due to potential redistribution of contaminants, increased impacts on marine resources, and considerably increased costs for control and disposal of contaminated sediments and material deposited in the disposal areas.

Step 5, Facility Footprint Constraint

The potential sites must have sufficient surface area available for placement of the required deepwater port configuration. Under the Applicant's commercial objectives for the Project, two unloading buoys would be required to enable continuous throughput of natural gas. Each unloading buoy and associated riser pipelines and anchor moorings would require a minimum circular footprint 1,798 m (5,900 ft) in diameter. In addition, the unloading buoys must be separated by a distance of 2 nautical miles (NM) to ensure safe navigation of SRVs to and from one unloading buoy, while another SRV is moored and regasifying LNG at the other buoy. Therefore, the port facility itself would require an approximate rectangular footprint of 1.8 km (1.1 mi) by 5.5 km (3.4 mi).

Phase 2 Conclusion

Figure 2.1-2 shows the results of the screening process. In stepwise progression, these figures indicate acceptable locations for a deepwater port facility in the Massachusetts Bay area by superimposing the spatial domains of each individual criterion defined above. The intersection of all these domains defines the area that is reasonable and feasible for siting a deepwater port facility, a location that falls within the Northwest Sector.

Phase 3, Deepwater Port Site Selection

The primary and secondary screening processes resulted in the selection of an area within Massachusetts Bay that is most feasible and reasonable for the siting of an LNG deepwater port facility. The preferred alternative area is a triangular-shaped area in northeastern Massachusetts Bay to the north of the Boston TSS and between the boundaries of the SBNMS and the South Essex Ocean Sanctuary (referred to as the Northeast Sector). Based on constraints from the required size of the facility footprint and the location of historic and active waste dumps in the area, there are only three alternative sites within the Northeast Sector where it would be reasonable and feasible to site the proposed facility. These three alternative Port locations, referred to as the Northern, Central, and Southern Port Sites, are shown on **Figure 2.1-3**.

- ***Northern Port Site.*** The proposed Northern Port Site is in the northern portion of the Northeast Sector (see **Figure 2.1-3**). The site is 2.0 km (1.25 mi) west of the SBNMS, 2.17 km (1.35 mi) east of the South Essex Ocean Sanctuary, 1.40 km (0.87 mi) northwest of the Massachusetts Bay spoil dumpsites mapped by the U.S. Geological Survey (USGS), and approximately 8.0 km (5 mi) north of the Boston TSS.
- ***Central Port Site.*** The proposed Central Port Site is in the central portion of the Northeast Sector (see **Figure 2.1-3**). The site is 4.0 km (2.5 mi) west of the SBNMS, 1.6 km (1 mi) east of the South Essex Ocean Sanctuary, 1.6 km (1 mi) west of the Massachusetts Bay spoil dumpsites mapped by the USGS, and approximately 3.1 km (1.9 mi) north of the Boston TSS.

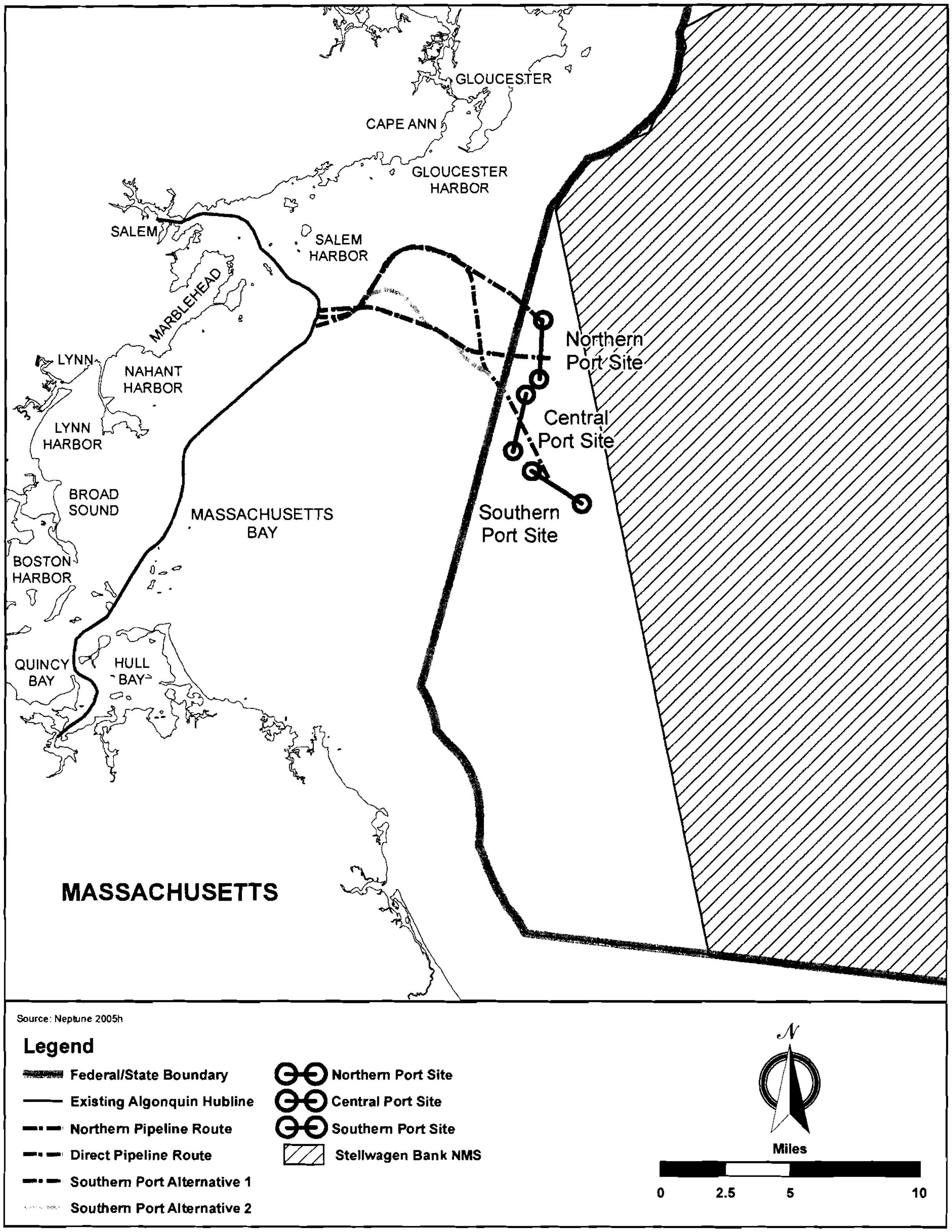


Figure 2.1-3. Neptune Project Alternative Port Sites and Pipeline Routes

- ***Southern Port Site.*** The proposed Southern Port Site is in the southern portion of the Northeast Sector (see **Figure 2.1-3**). The site is approximately 2.0 km (1.25 mi) west of the SBNMS, 3.2 km (2 mi) southeast of the South Essex Ocean Sanctuary, 1.2 km (0.75 mi) south of the Massachusetts Bay spoil dumpsites mapped by the USGS, and approximately 1.6 km (1 mi) north of the Boston TSS.

The Northern, Central, and Southern Port Site alternatives within the Northeast Sector are compared below relative to the following evaluation criteria:

- Benthic Habitat/EFH
- Marine Mammal Occurrence
- Commercial Fishing Use
- Suitability of Substrate
- Proximity to Disposal Sites
- Sediment Contamination
- Proximity to Shipping Lanes.

Benthic Habitat/Essential Fish Habitat

Field studies were undertaken to assess benthic habitat at the three alternative port sites, including video surveys to determine habitat types and sediment profile imaging (SPI) to assess sediment conditions and the nature and health of infaunal assemblages. The Northern Port Site has a predominance of low-complexity sandy mud bottom and a general lack of more complex hard-bottom habitat, as compared to the Central and Southern Port Sites. Species typically associated with hard-bottom habitats have longer recovery times once disturbed when compared to those species that would typically frequent the predominantly sandy mud bottom of the Northern port areas.

Results from the SPI survey revealed a low-energy, depositional environment with a relatively uniform sediment (primarily silt-clay with varying degrees of fine sand) over the entire area surveyed, except for three hard-bottom locations. The mooring anchors could be sited at all three port sites to avoid impacts on the hard-bottom areas from anchor installation or anchor line scouring.

The primary difference in potential benthic habitat impacts between the three alternative port sites is the amount of area that would be disturbed by the proposed pipeline installation (assuming selection of the Northern Pipeline Route alternative). The Central and Southern Port Sites would require an additional 4.8 and 9.7 km (3 and 6 mi), respectively, of pipeline than the Northern Port Site. Thus, the Central and Southern Port Sites would disturb 27 percent and 55 percent, respectively, more benthic habitat than would the Northern Port Site.

Marine Mammal Occurrence

The distribution of marine mammal sightings within the three Port Site Alternatives was compared using sighting data provided by SBNMS for the period 1979 to 2002. No sightings of North Atlantic right whales were reported in any of the three alternative port sites. Fin whales and humpback whale sightings were reported at all three Port Sites, but the number of sightings of both species at the Southern Port Site is slightly lower than at the Central and Northern Port Sites. This apparently less frequent occurrence of fin and humpback whales near the Southern Port Site, just north of the existing Boston TSS, is part of a larger corridor of lower frequency sightings that extends across SBNMS and is the stimulus for the proposed northern shift in the shipping lanes to lessen the risk of vessel strikes of marine mammals.

Commercial Fishing Use

Comparison of the Port Sites with respect to the potential effects of Port construction and operation are difficult because of the lack of site-specific information on fishing effort and catch. Catch data reported to the government are compiled for large areas, and fishermen are generally reluctant to provide specific information on the locations of their preferred fishing grounds or landings from such areas. Thus, the comparison must be conducted using indirect information, such as presence of target species, suitable habitat, and fishing gear such as lobster traps. This type of information was gathered during the field surveys conducted during the summer of 2005, but this information represents only a limited period and season.

Geophysical surveys documented extensive trawling activity (as evidenced by shallow parallel, linear scour marks in the sediment, which were visible on side scan sonar charts) throughout most of the soft-bottom areas at all three Port Sites. The bottom substrate and habitats are very homogenous throughout all three sites; therefore, fishery landings and value are expected to be similar between the three sites. Thus, impacts due to exclusion of fishing during operation of the Port would be nearly the same at all three alternative Port Sites. The presence of short-dumped debris within the Central and Southern Port Sites could provide some artificial habitat. In addition, because the Central and Southern Port Sites would require additional pipeline lengths of 4.8 and 9.7 km (3 and 6 mi), respectively, in comparison to the Northern Port Site, disturbances to the soft-bottom habitat from pipeline installation would affect much less fish habitat if the Northern Port Site were selected than if either of the other two Port Sites were constructed. Therefore, construction impacts on important commercial fish species would be less for the Northern Port Site than for the Central or Southern Port Sites.

The duration of pipeline construction within the port area would be shorter for the Northern Port Site than the Central or Southern Port Sites due to the shorter pipeline required. Thus, closure of fishing areas to avoid conflicts with construction vessels and activities during pipeline construction would be shorter for the Northern Port Site and, presumably, have less negative effects on commercial fishing activities than compared to the Central and Southern Port Sites.

Suitability of Substrate

The Northern Port Site is generally level with soft soils (clays) over bedrock or glacial till. The depth of soils varies from 7.6 to 29.0 m (25 to 95 ft). There are a number of bathymetric highs related to subcropping and outcropping of hard ground in each of the three alternate port sites. In these areas the soft sediment is either thin or absent. Except for these areas where hard ground is at or close to the seafloor, the soils are of sufficient composition and depth to provide suitable conditions for use of suction piles, the preferred type of anchor for the proposed anchoring/mooring system. The areas of shallow sediment and outcroppings are sparsely distributed throughout all three alternative port sites such that they would not pose constraints for anchor installation in any of the cases. The flexibility in selection of exact anchor placement locations would enable these outcrops/thin sediment areas to be avoided, regardless of which site is selected. Therefore, substrate suitability is not a differentiating criterion in the comparison of the three alternative Port Sites.

Proximity to Disposal Sites

All three alternative Port Sites are near the MBDS and two historical dump sites (Industrial Waste Site and the Interim Dredged Material Disposal Site) which overlap the MBDS and are east of the Central

Port Site. The Central and Southern Port Sites contain extensive debris fields, sonar targets, and magnetic anomalies, which are interpreted as being material intended for the designated dump sites that was either dumped outside of the designated areas or redistributed by trawling. The Central Port Site contains more than 700 magnetometer contacts and 190 sonar contacts. Less distinct debris piles are scattered between the major debris areas, suggesting that the waste material has been buried, mixed, and redistributed throughout much of the site. The Southern Port Site also has debris scattered throughout the site (440 magnetometer contacts and 150 sonar contacts), with especially abundant piles in the northwestern section of the site, closest to the dump site. Numerous linear trails and patches of the most recent spoil/debris suggest that the material was probably "short dumped" by vessels destined for the disposal site northeast of the Southern Port Site.

The proximity of the Port Site to the disposal area could also affect navigation. The area to be avoided ATBA surrounding the Port when an LNG vessel would be present would potentially require vessels transporting dredged material to the active disposal site to divert from a direct course. Each of the three alternative Port Sites could pose as a navigation obstruction for dump barges, depending on the originating Port and the course followed by the vessels. Therefore, this aspect of proximity to the dump site does not appear to be a relevant selection criterion in the comparison of Port Site alternatives.

Sediment Contamination

Low levels of contaminants were detected at all three proposed Port Sites but are not expected to pose any limitations to the Project. The Northern Port Site has the lowest occurrences/levels of contaminants, predominately due to its distance from known disposal areas and disposal areas recently identified through the Phase II geophysical surveys.

Proximity to Shipping Lanes

The proximity of the Port to the regional commercial shipping lanes could be a primary safety consideration. For sites closer to the commercial shipping lanes, there could be greater risk of collision from vessels that might stray from the designated shipping lanes. The Northern Port Site would be the most distant of the three sites from the commercial shipping lanes (e.g., the TSS), at a distance of 8.0 km (5.0 mi). Although the Central and Southern Port Sites would be viable locations for the Port, the Northern Port Site would provide the greatest buffer with commercial vessel traffic and, therefore, the largest margin of safety.

Phase 3 Conclusion

The Northern, Central, and Southern Port Sites have many similar characteristics and would be suitable sites. Because there are no clear environmental advantages between sites, the Northern and Southern Port Sites were selected for detailed evaluation.

The Central Port Site was not carried forward since it did not present a clear alternative to the sites selected.

2.1.1.4 Alternative Anchoring Methods

Installation of the mooring anchors for the two proposed offloading buoys would be one of the primary activities associated with construction of the Port having potential to cause environmental damage. There are a variety of available anchoring systems, each with its own suitability for varying environmental (e.g., seafloor, water depth, metocean) conditions, that also differ in the nature of their potential adverse impacts on marine resources associated with their installation. **Table 2.1-3** identifies the four types of systems and their primary characteristics.

Table 2.1-3. Alternative Types of Anchors

Alternative	Considerations	Characteristics
Embedment anchors	Soils	Versatile and accommodate wide range of soils.
	Impact	Large short-term impacts due to installation. Small long-term impacts.
	Decommissioning	Recoverable on decommissioning.
Suction piles	Soils	Sensitive to variations in soil type.
	Impact	Small short-term area of disturbed seabed from installation. Long-term loss of small benthic area.
	Decommissioning	Recoverable on decommissioning.
Driven piles	Soils	Designed to suit existing soil conditions.
	Impact	Small short-term area of disturbance and noise impact during installation. Long-term loss of small benthic area.
	Decommissioning	Usually abandoned in place.
Gravity anchors	Soils	Versatile, accommodates most soils.
	Impact	Moderate short-term impacts during installation. Moderate long-term loss of benthic area offset by potential artificial hard substrate of anchors.
	Decommissioning	Recoverable on decommissioning.

Criteria for evaluating the four anchoring alternatives were suitability of substrate, area of bottom disturbance, noise generated during installation, and recoverability on decommissioning. From an engineering design standpoint, the type of soils or substrate was generally deemed to be the major deciding factor in determining the most suitable anchor. Due to the potential presence of marine mammals in the project area and the susceptibility to adverse impacts from loud noise, noise generated by anchor installation is considered to be of primary importance in the selection of the preferred anchoring system.

- Embedment anchors are versatile and accommodate a wide range of soil types. As implied by the name, these anchor types are embedded in the soil by dragging them with heavy pull tugs. Thus, installation involves disturbance of the seafloor to a greater degree than any of the other alternatives, with impacts on benthic communities and water quality as well as the noise generated by tugs during installation. Embedment anchors can be recovered upon decommissioning of the Port.
- Suction piles require specific depths and types of soils, but disturb a limited bottom area. They are installed by placement on the seafloor and drawn into the soft sediments by lowering the pressure beneath them. They require a minimum of 7.6 m (25 ft) of surficial soils, but are highly reliable. Once installed, suction piles do not protrude above the seafloor.
- Driven piles are the most versatile anchoring system, being effective in almost any type of soil condition, and they have the smallest area of bottom disturbance of the four alternatives. The repetitive hammer blows needed to drive the piles into the sediment create significant sound pressure waves that have been demonstrated to cause behavioral changes and physiological damage to marine mammals' hearing ability, depending on the proximity to the

Port and the magnitude of the noise. Because of the significance of the marine mammal population in the Project area and the Port's proximity to SBNMS, potential impacts from pile driving could be major. This impact is evaluated in **Section 4** of this EIS/EIR.

- Gravity anchors are massive concrete objects that provide a stable anchor by their weight rather than by embedment in the seafloor. These are rapid and easy to install, as well as recover at the time of facility decommissioning, but would create a large obstruction on the seafloor for the life of the Project.

Final selection of anchor type would not be made until later in the design process. Accordingly, all four anchoring methods are evaluated in detail in this EIS/EIR.

2.1.1.5 Propulsion and LNG Vaporization

There are several SRV propulsion alternatives in combination with LNG vaporization technologies. Since many conventional ship propulsion systems use steam turbines for propulsion, the steam boiler is also available for producing steam as a source of vaporization heat. Alternately, if the propulsion system is separate from the vaporization system, then the propulsion system can be shut down when the SRV is docked at the Port. This allows the vaporization system to be optimized for a single purpose.

Propulsion and LNG Vaporization

Two of the propulsion alternatives considered were dual purpose, i.e., the propulsion system equipment served to meet the LNG vaporization needs as well. The first alternative considered was gas-fired propulsion steam boilers which would provide steam to turbine generators to propel the vessel and to heat the LNG in the vaporizer heat exchangers. The boiler steam would also be expanded through turbine generators to make electricity to run the LNG pumps and to meet ship hoteling requirements. The second dual purpose alternative was gas-fired turbines to propel the vessel during vaporization and generate electrical power; waste heat from electrical generation would be recovered to vaporize LNG and meet the ship electrical requirements as above. The steam boiler propulsion system is proven technology and used on many classes of vessels throughout the world. The gas turbine propulsion system is considered a novel concept and is not proven for this SRV application.

The two other propulsion system alternatives considered would require separate propulsion and LNG vaporization systems. In these cases, there would be no integration between systems. Both of these propulsion alternatives would be dual fuel diesel engine-based (burning 99 percent gas and 1 percent marine diesel oil), one being a slow speed diesel and the second, diesel electric. In both cases the heat required to vaporize LNG would be supplied by gas-fired auxiliary marine boilers. Electrical requirements would be supplied by dual fuel power generation engines.

At first glance, combining systems seemed to be the most efficient use of energy and hardware. After detailed economic and environmental lowest achievable emissions rate/best available control technology [LAER/BACT] studies, the Applicant determined this would not be the case.

The two diesel engine options evaluated resulted in far less air emissions and seawater consumption (with corresponding lower marine impact) than the two combined propulsion and LNG vaporization systems. In addition, the life cycle costs (which include capital and operating expenses) were lower for the two diesel options. Life cycle costs include fuel and maintenance for propulsion (round trip to and from LNG supply ports) and fuel for vaporization. With the exception of the gas turbine propulsion system, the other three systems would provide an equivalent level of reliability and safety and have been used in some type of marine application. The gas turbine option was dropped from further evaluation because of the reliability issue and, furthermore, because it was found to be the most costly alternative evaluated. The Applicant found the following (for all three alternatives, Net Present Value (NPV) was calculated over a 20-year period at an 8-percent discount factor):

- The steam boiler/steam turbine alternative would produce 99.9 tons of nitrogen oxide (NO_x) per year and use 40 million gallons per day (MGD) of seawater. The life cycle cost of this alternative was set as the baseline.
- The slow speed diesel alternative would produce 62 tons of NO_x per year, use 7 MGD of seawater, and have a life cycle cost of $53 million lower than the baseline.
- The diesel electric alternative would produce 52 tons of NO_x per year, use 7 MGD of seawater, and have a life cycle cost of $36 million lower than the baseline.

The Applicant found that either of the diesel alternatives would generate less impact on the air and marine environment than the steam boiler alternative. A life cycle cost analysis showed that both diesel alternatives would be less costly than the steam boiler option. Other environmental impacts would be identical for either diesel option. Based primarily on the significant reduction in air emissions, only the diesel electric alternative is carried forward for additional analysis. USEPA will evaluate the air pollution control technologies (and associated vaporization systems) proposed by Neptune, as part of its development of the applicable CAA preconstruction permits.

Open-Loop vs. Closed-Loop Vaporization

There are three available sources of heat to vaporize the LNG. They are burning part of the vaporized LNG, using the surrounding seawater to warm the LNG, or using the surrounding air to warm the LNG. Burning part of the LNG is generally referred to as a closed-loop system. Using the surrounding seawater is generally referred to as an open-loop system.

There are two basic types of system for the closed-loop vaporizers. Submerged combustion vaporization uses a burner that exhausts the hot combustion gases through a water bath to heat the water. The water then flows up through a tube bundle containing the LNG and vaporizes it. The water bath must be able to circulate over a weir and return through a downcomer to be heated again by the combustion gases. A shell-and-tube system uses steam to heat an intermediate fluid, such as propane or a water-glycol mixture. The intermediate fluid is then circulated over a tube bundle containing the LNG. The heated intermediate fluid vaporizes the LNG and is returned to the steam heat exchanger to be reheated. The intermediate fluid system can be completely enclosed.

Similarly for the open-loop system, in an open rack vaporizer the seawater is pumped to the top of an open water box that distributes it along the vaporizer. The water spills over the top of the water box and down a system of finned tubes containing the LNG. The seawater vaporizes the LNG. In the open-loop intermediate fluid system, the seawater can also be pumped through a heat exchanger to warm an intermediate fluid, such as propane or a water-glycol mixture. The intermediate fluid is then circulated over a tube bundle containing the LNG. The heated intermediate fluid vaporizes the LNG and is returned to the seawater heat exchanger to be reheated. The intermediate fluid system can be completely enclosed.

Because of the SRV's space constraints, air vaporization is not technically feasible for supplemental heating and would not work in the colder winter months when ambient air temperature is at its coldest. Therefore, air vaporization is not considered further.

Because the closed-loop system requires a portion of the vaporized LNG to be burned to provide the heat necessary to vaporize the cargo, the system has higher air emissions than the open-loop system.

The project area is in a nonattainment area for ozone, and therefore, emissions of NO_x and volatile organic compounds (VOCs) could contribute to degradation of the air quality.

Because the SPV port design was selected, the open-loop and closed-loop systems that require water to circulate over an open weir or water box would not be feasible because the SRVs will roll and pitch with the seas. Those systems require stable bases to maintain the surface of the water in relation to the weir or waterbox. Therefore, only the intermediate fluid versions of the open-loop and closed-loop systems were considered.

Closed-loop LNG vaporization systems are considered viable alternatives for this facility because the colder water temperatures make use of open-loop shell-and-tube vaporizer systems (using seawater as the heat source for vaporization) less reliable and effective. Open-loop shell-and-tube vaporizer systems must be designed to overcome the low ambient water temperatures, which would require supplemental heat sources during certain times of the year.

The year round seawater temperature averages 10.3 °C (50.5 °F), and varies from a low of 3 °C (37.4 °F) to a high of 18.4 °C (65.1 °F). For only a few months a year, seawater would be viable as the sole source of heat to vaporize LNG, without some form of supplemental heating by burning fuel. Thus, in the northeastern United States winter marine environment, a hybrid system employing both seawater and supplemental fuel combustion would be required to vaporize LNG. This hybrid system would have impacts on the marine environment and atmosphere. The circulating seawater flow would remain the same throughout the year, but the requirement for supplemental heating through most months of the year would result in additional air impacts.

Open-loop shell-and-tube vaporizer systems would create greater marine impacts than closed-loop systems. Based on seawater throughputs for open-loop shell-and-tube vaporizers used by Gulf Gateway in the Gulf of Mexico of 76 MGD, an open-loop system would require an intake of at least the same volume for LNG heating purposes during the summer months (when peak water temperatures in Massachusetts Bay approach average Gulf of Mexico winter temperatures). This water is then discharged at a temperature of 11 to 17 °C (20 to 30 °F) cooler than ambient except during periods of low water temperatures when supplemental heating would be required. Marine organisms (eggs and larvae) would be entrained in the once-through system. None are expected to survive due to physical damage caused by passing through the system, the temperature change, and the anti-fouling agents applied to the open-loop warming water system to retard marine growth. Secondary biological effects are fish impingement on intake screens and cold water discharge plume from the open-loop shell-and-tube vaporizer system.

During the initial screening process it is not clear whether the air quality impacts from the proposed closed-loop shell-and-tube vaporizer system, or the water quality impacts from the hybrid open-loop shell-and-tube vaporizer system using seawater to warm the LNG would be more significant. Therefore, both alternatives will be evaluated in more detail.

2.1.1.6 Alternatives for Marine Life Exclusion Systems

The Applicant has proposed to obtain engine cooling water (for the engines powering the revaporization process) via two sea chests located aft below the waterline. Openings to the sea chests would be approximately 1.6 m (5.25 ft) by 1.6 m (5.25 ft). Stainless steel wire screens over the sea chests would have slot sizes of 10 millimeters (mm) (0.39 inches) to 15 mm (0.59 inches).

Selection of a marine life exclusion system must be consistent with the operational and safety considerations of an oceangoing marine vessel, since the SRVs are used to transport the LNG to the Port and to vaporize it. The proposed design provides for a through slot intake velocity of less than the

USEPA-recommended velocity of 0.15 meters per second (m/s) (0.5 feet per second [ft/s]). It provides for exclusion of most juvenile fish.

Past deepwater port applications have considered aquatic filter barriers and cylindrical wedgewire screen barriers of variously sized gap openings and heights, resulting in the selection of 0.25-inch gap screens. For shipboard applications, neither cylindrical wedgewire screens nor fabric filters are practical. If smaller slot sizes are used, either the intake velocity must be increased, which would threaten impingement of a greater number of marine organisms, or the hull openings would have to be enlarged, threatening vessel integrity.

Since the proposed intake structure design would result in an intake velocity of 0.12 m/s (0.39 ft/s) and alternative technologies did not offer increased protection for marine organisms without jeopardizing vessel integrity, the Applicant's proposed intake structure design is the only alternative carried forward for detailed evaluation.

2.1.1.7 Alternative Biocide Systems

The Port as proposed would use approximately 2.39 MGD of seawater to cool the engines producing power for the LNG revaporization process. The water would also be used for ballast control as the LNG cargo is vaporized. Therefore, there would be no biocide treatment of the seawater if the closed-loop, shell-and-tube vaporization system is selected.

If the open-loop shell-and-tube vaporizer system is selected, 76 MGD will be required to provide thermal energy for the vaporization process. To maintain the heat transfer surfaces of the heat exchangers, marine growth in the warming water system must be controlled to preclude fouling and loss of efficiency. Accumulations of algae and other marine growth could promote pitting corrosion, which could lead to leaks in the intermediate fluid loop resulting in greater maintenance needs and lower system availability. Biological control must not only render incoming biological material incapable of growth, but it must carry a residual concentration through the system to protect it from new growth caused by airborne biological agents or prior contamination that could possibly cause growth in the system.

There are generally four options for controlling biological growth. In evaluating them, principal consideration is given to safety, maintenance, chemical usage, residual protection, cost, and offshore issues. These four alternative biocide systems, based on specific processes, are summarized in **Table 2.1-4** and are discussed below.

Ultraviolet Light

One alternative would be to use ultraviolet (UV) light to control biological growth in the cooling system. In addition to the cost of replacement bulbs and other supplies, the cost of maintaining the UV lights and replacing the bulbs could become excessive on systems as large as those required for the Port. Also, UV light does not leave a residual to adequately protect the piping system.

Ozone

Ozone kills biological materials and is used in potable water and wastewater treatment applications. Ozone could be generated aboard the SRVs with electrically powered, commercially available ozone generators. The use of ozone would raise the problem of metallurgy requiring corrosion-resistant materials since ozone accelerates corrosion in water. This would require a metallurgy upgrade of the system. The ozone could accelerate the corrosion of the cooling system, causing a shortened life span

Table 2.1-4. Biocide Alternatives

Process	Residual Control	Capital Cost	Safety	Deck Area	Operating Costs	Remarks
Ultraviolet light	No	High	Safe [a]	Low	High	Not proven offshore
Ozone	No	Medium	Potentially unsafe [b]	Medium	Medium	Not proven offshore
Chlorine dioxide	Yes	High	Potentially unsafe [c]	High	High	Not proven offshore
Sodium hypochlorite	Yes	Low	Safe	Low	Low	Many offshore applications

Notes: [a] Requires diving to replace and maintain lights.
[b] Environmental hazard of ozone generation.
[c] Requires handling and storage of hazardous chemicals in a limited space.

and possible failure. Ozone, like UV, does not leave a residual because it is reactive and would be consumed in the first few seconds after application. Ozone generation would also require an ozone destruct unit (fired unit) to destroy any excess ozone production that would be harmful to the atmosphere. An ozone generator would require a pure or enriched source of oxygen that could be supplied from either a pressure swing absorption unit or liquid oxygen tank.

Chlorine Dioxide

Chlorine dioxide is effective and leaves a residual that would protect the cooling system. Chlorine dioxide would be generated using several chemicals that are hazardous, thereby possibly posing a risk to personnel. Special generation equipment would be required that would consume a large area of deck space, along with chemical storage. Capital and operating costs would be higher than most other alternatives, and shipboard installation would require some adaptation for offshore operation.

Sodium Hypochlorite

Sodium hypochlorite is generated in a sodium hypochlorite generator by passing electrical current through seawater, causing it to form sodium hypochlorite and small amounts of hydrogen. The hydrogen would be vented to a safe location (in a dilute form below its lower explosive limit) and readily dispersed since it is lighter than air. Sodium hypochlorite generators can be continuously controlled to maintain total residual chlorine (TRC) levels of 0.1 milligrams per liter (mg/L) that would protect from airborne algae that could cause algae growth. Sodium hypochlorite generators have been used in a variety of applications with good results and minimal problems.

UV and ozone generator options, in addition to presenting operational problems, would not be feasible because they fail to provide the required residual biological control. Although chlorine dioxide would provide residual control, it would require use of hazardous chemicals and would consume considerable deck space for production and chemical storage. The only viable remaining option would be use of sodium hypochlorite generated on site with seawater and electricity. This option has been used successfully for a long time on many offshore once-through seawater applications. Alternatives to use of sodium hypochlorite are not feasible. Accordingly, further evaluation of those alternative systems is not conducted in this EIS/EIR.

2.1.1.8 Alternative Pipeline Routes

Four alternative pipeline route corridors have been identified for the transmission of natural gas from the Port to the HubLine pipeline tie-in point. These pipeline alternatives are referred to as the Direct Pipeline Route, the Northern Pipeline Route, the Southern Port Pipeline Alternative 1 and the Southern Port Pipeline Alternative 2. All pipeline alternatives are shown in **Figure 2.1-3**. The following discusses the criteria used by the Applicant in evaluating the potential routes from their preferred Port site, the Northern Port Site. The Southern Port Pipeline Route Alternatives 1 and 2 closely follow either the Northern Pipeline Route or Direct Pipeline Route, therefore the following discussion will relate closely to these alternatives also. **Table 2.1-5** outlines each pipeline route alternative.

Table 2.1-5. Pipeline Route Alternatives

Port Site Associated with Pipeline Route	Pipeline Route Alternative	Length	Construction Footprint	Construction Method
Northern Port Site	Northern Pipeline Route	17.5 km (10.9 mi)	85 acres	Conventional trenching using anchor barges
Northern Port Site	Direct Pipeline Route	14.7 km (9.1 mi)	70 acres	Conventional trenching using dynamically positioned barges
Southern Port Site	Southern Port Pipeline Alternative 1	25.9 km (16.1 mi)	124 acres	Conventional trenching using anchor barges
Southern Port Site	Southern Port Pipeline Alternative 2	21 km (13.2 mi)	102 acres	Conventional trenching using anchor barges

Effects on Benthic Habitat/Essential Fish Habitat

Field studies, including video surveys to determine habitat types and SPI have been made to assess sediment conditions and the nature and health of faunal assemblages. The SPI survey documented distinct differences in both sediment type and faunal characteristics between the proposed Northern Pipeline Route versus the Direct Pipeline Route. While both routes have mature benthic communities that show little signs of stress from prolonged or frequent disturbance, and both routes display the general trend of a gradual fining of sediment from west to east proceeding from shallow to deeper water (medium to fine sand transitions into silt/clay facies with increasing depth), the sediments along the Direct Pipeline Route were much more variable and included numerous bands of rock or till outcrops (as clearly identified in the geophysical survey) interspersed between the sandy and muddy areas.

The results of the benthic video survey confirm that the benthic habitats along the Northern Pipeline Route, which are predominantly low complexity sandy mud bottom, compared to the pebble/cobble and partially buried or dispersed boulder habitat, which composes approximately 2.1 km (1.3 mi) (15 percent) of the habitat along the Direct Pipeline Route. Species typically associated with hard-bottom habitats have longer recovery times, once disturbed, when compared to those species that would typically frequent the predominantly sandy mud bottom of the Northern Pipeline Route. In addition, commercial lobsters and scallops were observed more often along the Direct Pipeline Route than along the Northern Pipeline Route.

Based on the benthic surveys conducted, the area traversed by the Direct Pipeline Route appears to be a more valuable resource for fish habitat than that traversed by the Northern Pipeline Route, both in terms of potentially available prey as well as structural habitat diversity.

Effects on Marine Protected Areas

Each proposed pipeline route would traverse state marine sanctuaries, which are unavoidable by any pipeline route from outside state waters to the HubLine pipeline. The Northern Pipeline Route would traverse 4.5 km (2.8 mi) of the North Shore Ocean Sanctuary and 11.4 km (7.1 mi) of the South Essex Ocean Sanctuary. The Direct Pipeline Route would cross 12.4 km (7.7 mi) of the South Essex Ocean Sanctuary. Thus, the Direct Pipeline Route would traverse a smaller distance (3.5 km [2.2 mi]) in a state marine protected area than the Northern Pipeline Route.

Effects on Commercial Fishing

Comparison of the proposed routes with respect to the potential effects of pipeline construction and operation on fishing activities are difficult because of the lack of site-specific information on fishing effort and catch. Catch data reported to the government is compiled for large areas, and fishermen are generally unwilling to provide specific information on the locations of their preferred fishing grounds or landings from such areas. Thus, the screening comparison must be conducted using indirect information, such as presence of target species, suitable habitat, and fishing gear, such as lobster traps. This type of information was gathered during the field surveys conducted during the summer of 2005; this information represents only a limited period and season.

The geophysical surveys documented extensive trawling activity (as evidenced by shallow parallel, linear scour marks in the sediment, which were visible on side scan sonar charts) throughout most of the soft-bottom areas on both alternative routes. Although the Northern Pipeline Route contains more soft-bottom sediments than the Direct Pipeline Route and, therefore, might be used more extensively for trawling, the greater presence of hard-bottom habitats along the Direct Pipeline Route, as documented by both the geophysical and benthic surveys, provides more suitable habitats for lobster and groundfish. Furthermore, disturbances to the soft-bottom habitat from pipeline installation would have shorter-term effects on habitats and prey than on hard-bottom habitats, which take longer to repopulate. Therefore, impacts on important commercial fish species would be anticipated to be less for the Northern Pipeline Route than for the Direct Pipeline Route.

Due to the soft, more easily plowed sediments that predominate more of the Northern Pipeline Route than the Direct Pipeline Route, the duration of construction would be expected to be shorter for the Northern Pipeline Route (even though it is 2.8 km [1.8 mi] longer than the Direct Pipeline Route). Thus, closure of fishing areas to avoid conflicts with construction vessels and activities during pipeline construction would be shorter for the Northern Pipeline Route and, presumably, have less of a negative effect on commercial fishing activities than would the Direct Pipeline Route.

Sediment Contamination

The adverse impacts on sediment and water quality could differ between the alternative pipeline routes, depending on the degree to which contaminated sediments are potentially disturbed during pipeline construction. The Applicant assessed these potential effects by the distance that the proposed routes would traverse historic dumping areas and areas of potentially contaminated sediment, based on results of geophysical surveys and laboratory analyses of sediment cores.

Both alternative pipeline routes traverse a historical waste disposal site near their proposed interconnection points with the existing HubLine pipeline. Furthermore, there is a debris field within the proposed corridor for the Direct Pipeline Route, which could represent waste material. Sediment cores taken along the Northern Pipeline Route were found to have fewer kinds and lower levels of contaminants than cores collected along the Direct Pipeline Route, probably due to their respective distances from known disposal areas and disposed material identified by the geophysical surveys. None of the types and levels of contaminants detected in sediments along either route should pose any limitations to the Project.

Effects on Cultural Resources

Based on remote sensing data from the geophysical surveys, two underwater shipwrecks were identified along the Northern Pipeline Route within the anchoring corridor for the pipeline lay barge. These features could be avoided during construction by implementing barge anchor plans. Two wrecks were also identified within the proposed pipeline corridor along the Direct Pipeline Route. The Direct Pipeline Route was adjusted to avoid these resources by a minimum of 152.4 m (500 ft). Construction and operation of the pipeline along either alternative route should not result in impacts on cultural resources.

Geotechnical Conditions

The Direct Pipeline Route would pass through a restricted corridor that passes between morphological highs, where bedrock and glacial tills outcrop. The predominant soils encountered within the upper 6 feet are very soft clays within the eastern section of the route and fine sands to the west (adjacent to the HubLine). Approximately 5.0 km (3.1 mi) (34 percent) of the route, primarily near the western end, pass through areas where surficial soils are less than 1.5 m (5 ft) thick. Within these areas, reworked glacial deposits would be encountered. This unit is likely to consist of poorly sorted sand gravels and cobbles in a silt/clay matrix. Boulders, stiff clay, and dense sands also might be encountered. Review based on the Phase 1 geophysical and geotechnical survey results confirmed that the Direct Pipeline Route is trenchable.

The surficial soils along the Northern Pipeline Route are predominantly fine marine silts and clay grading to fine sands inshore. The depth to bedrock or tills is generally greater than 6.1 m (20 ft). Due to the predominance of soft soils, trenching and backfilling of the Northern Pipeline Route would be expected to be up to twice as fast as for the Direct Pipeline Route. A further advantage of the Northern Pipeline Route is that a straighter connection between the Northern Port Site flowline and the Northern Pipeline Route could be achieved. This would avoid a T-connection, which would be required for the Direct Pipeline Route, providing improvements to pipeline constructability and system commissioning. The Northern Pipeline Route parallels the existing Hibernia fiber optic telecommunications cable for a significant length (8.4 km [5.2 mi] within 500 m [1,640 ft] and 1.1 km [0.7 mi] within 91.4 m [300 ft]), while the Direct Pipeline Route does not parallel the cable. Both routes cross the cable.

Construction Cost

The main cost differences between the Northern and Direct Pipeline routes are due to the greater length of the Northern Pipeline Route as compared to the Direct Pipeline Route (17.5 km [10.9 mi] vs. 14.7 km [9.1 mi]) and the varying soil conditions within the respective areas of each route. The 17 percent greater pipeline length of the Northern Pipeline Route would result in 17 percent greater material costs than for the Direct Pipeline Route. The Direct Pipeline Route crosses an area with stiff soils, boulders, and areas of shallow bedrock/glacial till which contrasts with the substrate along the Northern Pipeline Route, which has a 3.0-m (10-ft) minimum thickness surface layer of silt, sand, or soft clays. Therefore, the Direct Pipeline Route would be slower to trench, resulting in greater installation costs. Estimated costs are shown in **Table 2.1-6**.

There might be areas along the Direct Pipeline Route that would require a second pass of the plow and possibly additional protection in the form of artificial backfill or mats where designed cover depths are not achieved. This would add additional cost to the Project in terms of vessel time and possible schedule delay. If an anchored barge is used to lay and trench the pipeline, there could also be more delays along the Direct Pipeline Route due to anchoring difficulties in hard soils.

Table 2.1-6. Estimated Pipeline Construction Costs

Item	Northern Pipeline Route	Direct Pipeline Route
Materials	$44,282,000	$38,088,000
Installation	$43,260,000	$46,935,000
Total Cost	$87,542,000	$85,023,000

Conclusion

The differences between the Northern and Direct Pipeline Routes can be summarized as follows:

- The Northern Pipeline Route, although 2.8 km (1.8 mi) longer than the Direct Pipeline Route, traverses only soft-bottom (clay and sand) habitats, as compared to the Direct Pipeline Route, which crosses approximately 2.0 km (1.3 mi) of hard bottom (gravel with cobbles). Given that soft-bottom habitats generally support fewer important commercial species and are more resilient to disturbance than hard-bottom habitats, the impacts on fish and marine communities would be less if the pipeline were constructed along the Northern Pipeline Route than the Direct Pipeline Route.
- Construction along the Northern Pipeline Route would take less time due to the complete avoidance of gravel, cobble, and other hard substrates and lack of thin surficial sediment layers as compared to the Direct Pipeline Route. There would be less risk of incurring trenching or burial problems along the Northern Pipeline Route. Therefore, the duration that the unburied pipeline would obstruct lobster movement or trawling would be shorter than for the Direct Pipeline Route.
- Although both routes traverse a historical disposal site, the Direct Pipeline Route is near two other former disposal sites and some documented areas of debris. Although levels of contamination from collected sediment cores along both routes are not cause for concern, the Northern Pipeline Route sediment samples generally had fewer and lower levels of contaminants than did the Direct Pipeline Route samples. Installation of the pipeline along the Northern Pipeline Route would be less likely to disturb or disperse contaminated sediments.

Both routes involve feasible alternatives. Therefore, detailed evaluation of both routes will proceed. The noted differences between the two routes are not sufficient to warrant elimination from further consideration of the Direct Pipeline Route.

Single Pipeline Alternative

In addition to the Neptune application, Excelerate Energy has submitted an application for a license to construct own and operate a LNG deepwater port called NEG in close proximity to the Neptune Port. The NEG Project is based on similar SPV technology as that proposed for the Project. The NEG Project also calls for constructing two unloading buoys that would be connected to the HubLine by a separate natural gas pipeline. Constructing a single pipeline to serve both proposed projects is not considered an alternative to the pipelines being evaluated to support the proposed Port alternative locations. A single pipeline is feasible only if both proposed projects are licensed and constructed. Therefore, the potential reduction in impacts associated with a single pipeline instead of separate pipelines for Neptune and NEG are discussed in **Section 6.2.2.6**.

2.1.1.9 Alternative Port Construction Schedules

In its original license application, the Applicant proposed to construct the deepwater port during winter months. Based on recommendations subsequently provided by USEPA and other agencies, the Applicant considered alternative construction schedules. Also, the proposed construction schedules include contingencies for weather delays and provide for contingency plans that address equipment mobilization, installation sequence, weather, and offshore construction problems.

The Applicant considered the timing of construction based on design and construction preferences and weighing of the potential impacts on marine animal species, fishing, and other uses of the project area. The environmental considerations included weighting the importance of species (economically important and protected species), the potential for impact, and the degree of impact and ability to mitigate impact.

Sequence of Construction

The sequence of construction would be to start laying the pipeline from the southernmost buoy through the port area and continuing westward (i.e., offshore to inshore) toward the HubLine pipeline tie-in. Separate components that would be installed in conjunction with the pipelay would be the two port manifolds, the Hibernia cable crossing, and the HubLine hot tap.

Under ideal conditions, the pipeline would be laid in 3 to 5 weeks. Use of a dynamic positioning pipelaying vessel would require 3 weeks; use of conventional anchoring lay vessels would require 4 to 5 weeks. Plowing of the trench and burying the pipeline would follow the laying of the pipeline and would require approximately 2 weeks (1 week each to cut the trench and backfill the trench with the installed pipeline). Using sequential lying and plowing of the pipeline would mean that any given segment of the pipeline would be lying on the seafloor (i.e., creating an obstruction) for approximately 3 weeks.

Installation of the port anchors would probably begin soon after the pipelaying vessels and activity have cleared the port area. Sixteen anchors would be installed, one at a time, taking approximately 1 day per anchor. The installation of the risers, buoys, and umbilicals would occur following anchor installation, during the time the pipeline is being installed. Under ideal conditions, the total duration of the port construction and commissioning would be approximately 4 months; a 2-month contingency would be built into the schedule to allow for delays.

Primary Environmental and Socioeconomic Criteria

The primary environmental and socioeconomic concerns relevant to the timing of construction are fishing activity (primarily lobster and bottom fish), marine mammals (North Atlantic right whale, humpback, and fin whales), and spawning of fish.

- *Bottom fishing and gillnetting.* Some or all of the project area is closed to bottom trawling and gillnetting during April through June and October through November as NOAA Rolling Closure Areas, as shown in **Figure 2.1-4**. Fishermen have indicated that if there is temporary exclusion of fishing due to construction, they would prefer to have construction occur during the rolling closures when the area to be affected by construction is already closed to bottom trawling and gillnetting.
- *Lobster/lobster fishing.* Information from lobstermen and from the benthic video survey indicate that most of the Project area has few to no lobsters or lobster fishing gear during the month of July, when most lobsters and lobstering activity have moved inshore. Lobsters generally move from deep water into shallow inshore waters as the water warms; therefore, a pipeline installation sequence from offshore to inshore during June and July coincides well with respect to avoiding lobsters.
- *Mid-water trawling.* There is no significant commercial fishing for tuna and menhaden in the Project area. Commercial fishing operations for herring should not be affected by construction, unless there is an unusual concentration of herring that occurs in the Project area. Although there are only two local mid-water trawlers that fish for herring, if major schools developed in the Project area there could be a need to stop construction during the period that trawlers are active in the construction area.
- *North Atlantic right whale/humpback whales.* Although North Atlantic right whales have been sighted in every month of the year, they are primarily present in Massachusetts Bay during February through May. There are very few right whale sightings after mid-May. Fin and humpback whales are present from March/April through November and cannot be avoided unless construction occurs in the winter. Humpback whale numbers begin to increase on SBNMS waters in or about June and normally persist throughout the summer to early fall period.
- *Fish spawning.* Some species of fish spawn in Massachusetts Bay in every month of the year, so timing construction to avoid spawning periods of all fish is impossible. The suitability of spawning habitat along the pipeline route would dictate whether impacts on spawning grounds would be affected by construction if it took place during the respective spawning periods.
- *Whale-watching and recreational fishing.* Other commercially important activities besides commercial fishing, such as whale-watching, charter and head boat fishing, and recreational boating could be adversely affected by summertime construction (primarily by exclusion from areas where construction activities are occurring). Measures other than seasonal timing of construction, such as sequencing or overlapping construction activities to reduce the duration of construction in a given area, can be used to mitigate adverse effects of construction on these activities.

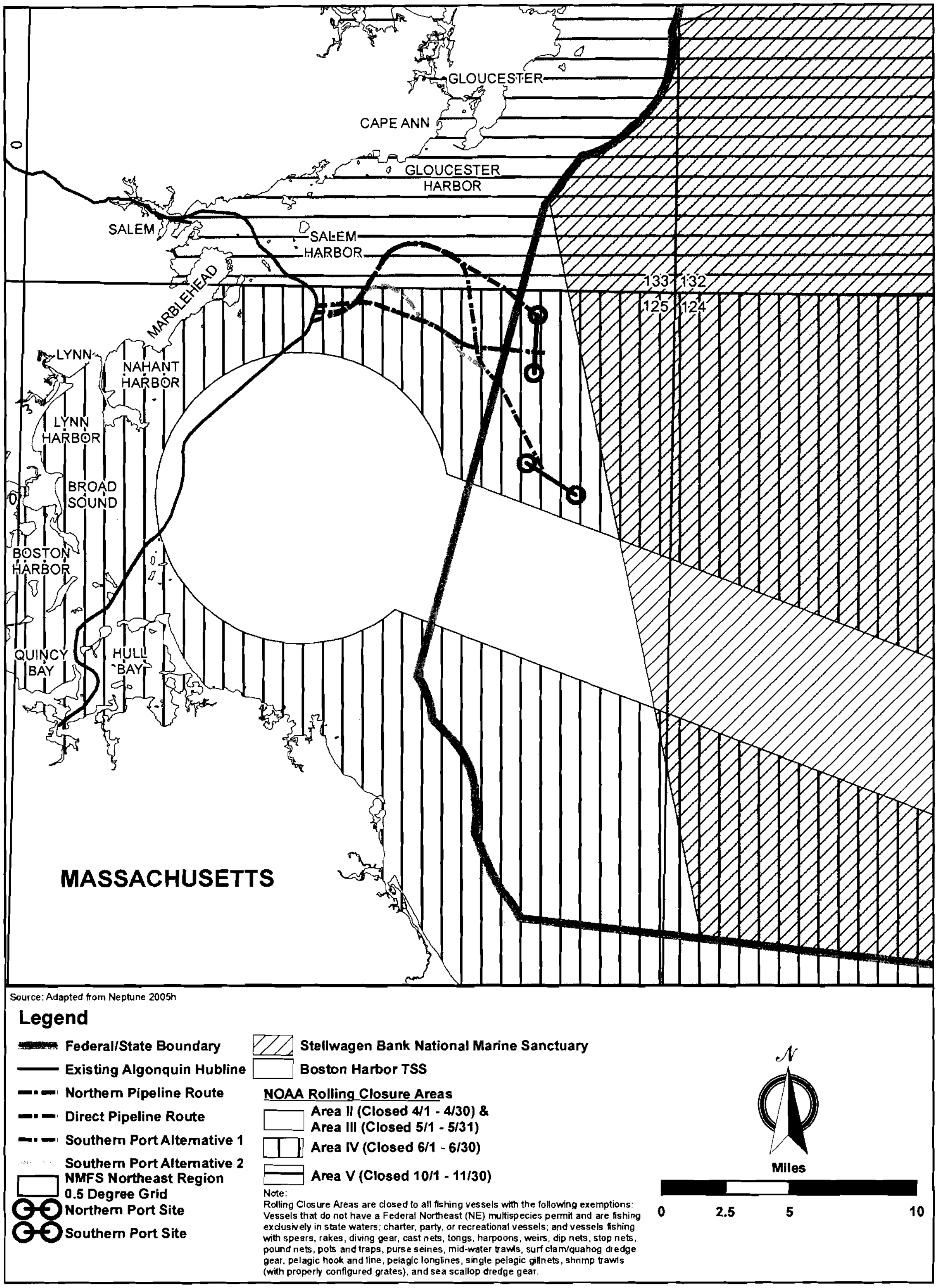


Figure 2.1-4. NOAA Rolling Closure Areas in the Vicinity of the Neptune Project

Summer Construction Schedule Alternative

A summertime construction schedule is shown in **Figure 2.1-5**. Although the duration of construction activities is conservatively estimated, this schedule does not include a buffer for contingencies. Therefore, the Applicant developed an alternative schedule that incorporates potential weather or equipment delays, as shown in **Figure 2.1-6**. This contingency schedule adds approximately 2.5 months to the construction schedule, resulting in a late November completion rather than mid-September. The Applicant intends to plan and design the Project construction process to meet the schedule shown in **Figure 2.1-5**, but conduct its environmental consequences analysis and request permits based on the contingency schedule presented on **Figure 2.1-6**. Construction would be completed between mid-May and the end of November. As illustrated in **Figure 2.1-7**, during this period:

- Few if any North Atlantic right whales are likely to occur in the Project area.
- Lobsters and lobster fishing appear to be at their lowest levels of the year in the Project area for 4 of the 8 months of this period. Pipeline construction would be completed prior to lobsters and lobstering activity moving back into the pipeline area.
- Bottom fishing and gillnetting would be prohibited in most of the Project area for at least a portion of the construction period.
- Construction would occur during peak spawning periods for several species of commercially important fish. Sediment suspension caused by pipeline trenching would be minimized by use of a plow, which would significantly restrict the area and duration of bottom-disturbing activities in comparison to dredging or jetting.
- The best weather of the year occurs in the summer months. Thus, the duration of construction is least likely to be delayed due to bad weather than at any other season of the year. Completing the construction in the shortest possible time would be the best strategy for minimizing adverse environmental effects.

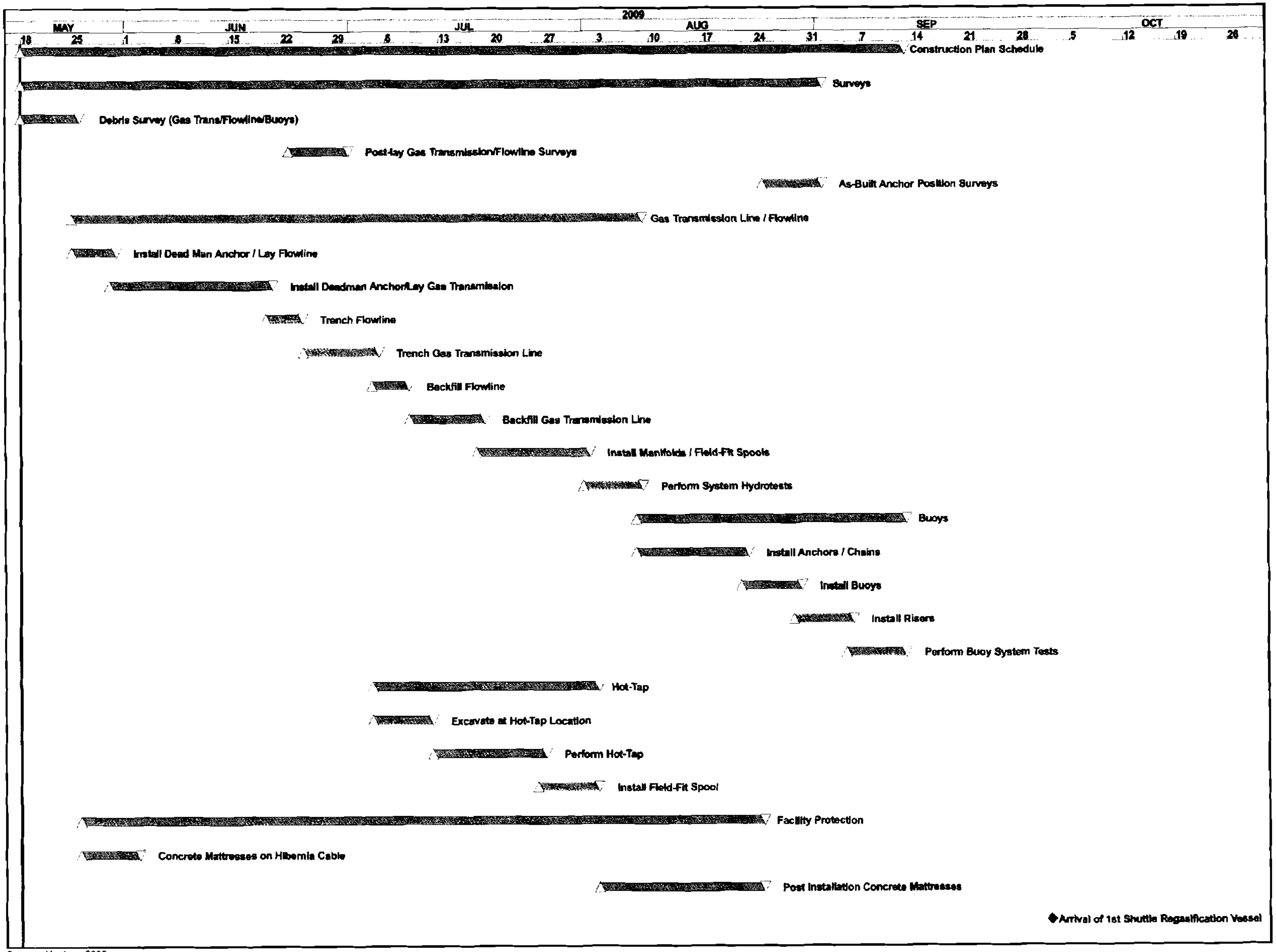
Winter Construction Schedule Alternative

A Winter Construction Schedule is considered an alternative to a summer construction period.

- The Applicant's proposed summer construction duration, including additional time to cover contingencies, would be 6 months. A winter construction period would incur additional weather delays that would significantly extend the construction period and, therefore, a 9-month pipeline construction schedule appears reasonable. Consequently, a Winter Construction Schedule for the specific period from September through May was considered.

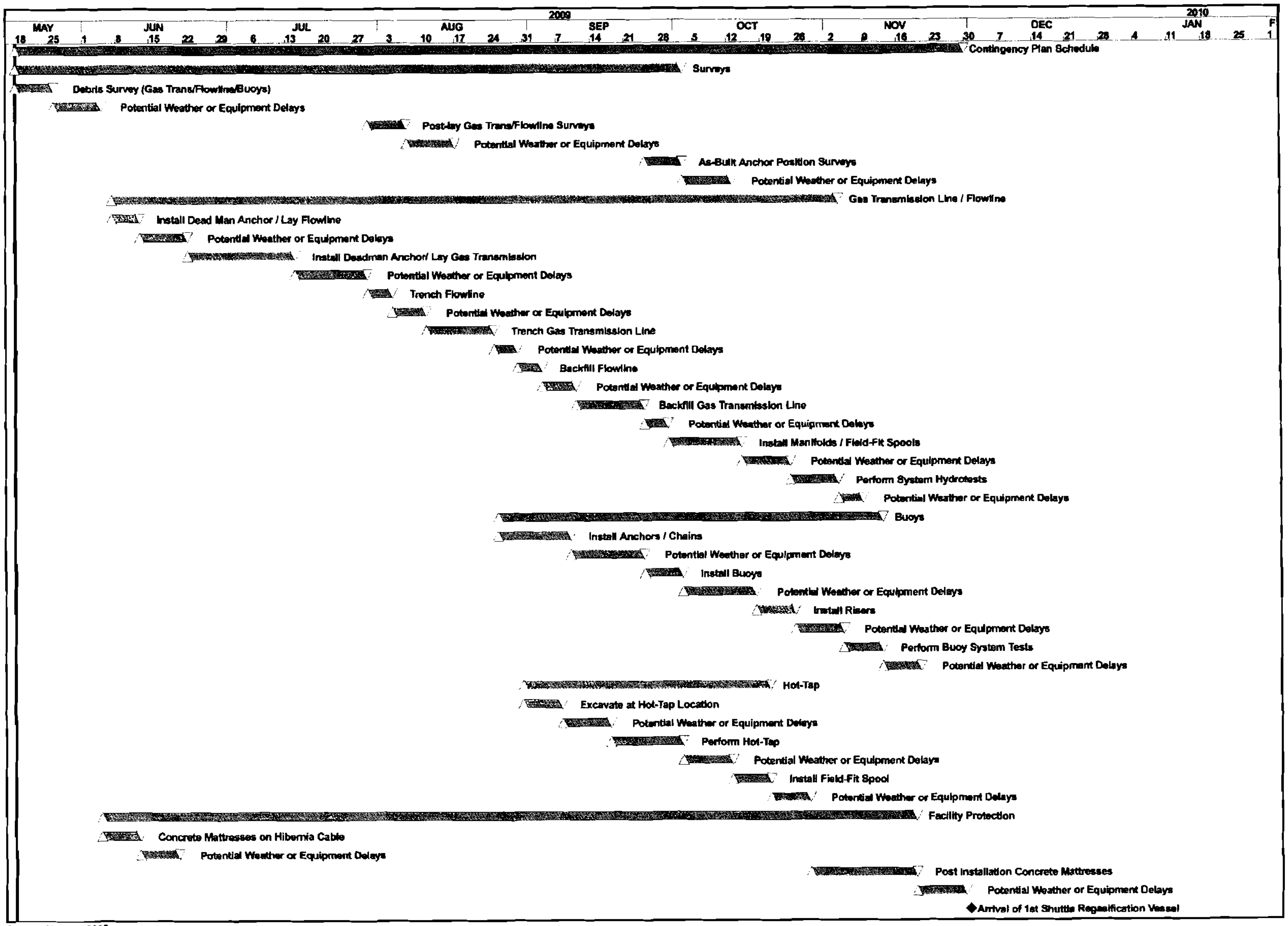
Advantages of a Winter Construction Schedule would include

- Construction would avoid the summer peak occurrence of, and fishing for, several pelagic fish species such as bluefin tuna, Atlantic herring, bluefish, and Atlantic mackerel.
- Bottom fishing and gillnetting would be prohibited in most of the project area for 4 of the 9 months of construction (October through November and April through May), avoiding potential conflicts with fishing activities during almost half the construction period.



Source: Neptune 2005e

Figure 2.1-5. Neptune Project Summer Construction Schedule



Source: Neptune 2005e

Figure 2.1-6. Neptune Project Summer Construction Contingency Schedule

Notes:
[a] Rolling closed areas are closed to all fishing vessels except those with exemptions (NMFS 2004a).
[b] Right whales have been sighted off Massachusetts in most months, but occurrences are highest between February and April (McLeod 2002).
[c] Humpback whales arrive in Massachusetts Bay in March to feed, but move offshore towards SBNMS in April where they remain until mid-November. Peak occurrences are in May and June (McLeod 2002).
[d] Sperm whales are reported year-round offshore of Massachusetts, but peak numbers occur in the summer months (NOAA 1993).
[e] Sei and blue whales have been reported in Massachusetts waters during the summer months, but their occurrence in the project area is rare (Waring et al. 2004).
[f] Lobsters migrate from deep offshore waters in spring and early summer and back into deep waters in late fall and early winter, it was assumed they could occur in the project areas during this migration (Cooper and Uzman 1970).
[g] Sea turtles occur in the project area primarily in the summer months, and typically begin a southward migration when water temperatures begin to decrease in October or November (Bell 2003).
[h] In general, winter flounder spawn inshore in the winter and migrate offshore to deeper waters in the summer (Pereira et al.1999).
[i] Adult and juvenile yellowtail flounder migrate away from coastal areas off southern New England during autumn (Johnson et al. 1999). Eggs and larvae occur April through October (Hare 2006).
[j] Cod occur in Massachusetts Bay and Western Gulf of Maine throughout the year and do not migrate. Spawning also occurs throughout the year, with a peak in Massachusetts Bay in January and February and peaks in the Gulf of Maine in early spring and winter (Lough 2004). Eggs are found in the project area in all months but September (Hare 2006).
[k] Atlantic herring spawn in the Gulf of Maine July through November and migrate to overwintering areas off of Cape Cod and the Mid-Atlantic Bight in the late fall. Eggs are demersal (Stevenson and Scott 2005).
[l] Spawning can occur from August through October, but scallops can occur in the project area throughout the year (Hart and Chute 2004).

Figure 2.1-7. Time of Occurrence for Species of Concern Compared to the Summer and Winter Construction Schedules

Disadvantages of a Winter Construction Schedule would include

- The peak occurrence of North Atlantic right whales is February through April, which could result in construction-related impacts due to vessel strikes and noise.
- Lobsters and lobster fishing in the project area would be near their maximum levels during the fall (October and November) and spring (April and May) months. Although pipelaying and installation would only overlap these peak months during November, other construction activities occurring during these months would create potential impacts on lobsters and conflicts with lobster fishing activities.
- Although peak spawning periods for several species of commercially important fish (hake, silver hake, and witch flounder) would be avoided, the period coincides with spawning of many others (Atlantic cod, haddock, winter flounder, and pollock).
- Severe storms occur frequently during this period. Thus, construction delays due to bad weather could be significantly greater than a Summer Construction Schedule.

Alternative Construction Schedule 1

A third construction schedule is considered as an alternative to both the summer and winter construction period, and would be from January to July. This third schedule will look at dividing the Winter and Summer Construction Schedules to divide species specific impacts.

A seasonally divided construction schedule would be expected to incur some weather-related construction delays during the colder months, while reducing impacts on marine species. The 9-month period proposed for the Winter Construction Schedule appears reasonable, as well as the 6-month summer schedule. Therefore it seems reasonable that a seasonally divided construction schedule would take around 7 months.

Advantages of a seasonally split construction schedule would include

- Lobster abundance would beat seasonal lows in the Project area for 4 of the 7 months
- Potential impacts on sea turtles would be minimized by avoiding construction when they are most abundant in the area for 4 of the 7 months
- Interference with commercial fishing operations during summer and fall would be avoided
- Construction would occur during a period of low lobster landings for 5 of 7 months.

Disadvantages of a seasonally split construction schedule would include

- Construction would occur when the North Atlantic right whale is most abundant in the Project area
- Hydrostatic testing would occur during spring when phytoplankton, zooplankton, and ichthyoplankton densities are increasing, but would avoid periods of peak abundance for the eggs and larvae of lobsters and sea scallops
- Construction would occur during the beginning of the spring peak of the eggs and larvae of yellowtail flounder.

Conclusion

Construction during September through May would appear to conflict with the peak occurrence or spawning of many important species of marine mammals, fish, and shellfish. Furthermore, the winter construction period would extend the duration of construction due to weather delays, which could conflict with completing the construction in the shortest possible time to minimize adverse environmental effects. A construction schedule having offshore activities during winter months would incur some additional risks of impacts on biota and could result in additional construction delays. **Figure 2.1-7** contains a list of species of concern and the most likely time of occurrence.

Construction during May through November would coincide with the presence of fin and humpback whales. It would also conflict with the peak occurrence or spawning of some species of fish and shellfish.

Construction during January through July would divide the conflict with the peak occurrence of spawning for marine mammals, fish, and shellfish. This construction schedule also runs a greater risk of weather delays, resulting in indirect impacts on biota.

Without additional evaluation and consultation with resource agencies, it is unclear which construction schedule represents the best possible timeframe for biological resources. Therefore, construction schedules with offshore construction during the summer months, winter months, and a combination of both are evaluated in detail in this EIS/EIR.

2.1.2 No Action Alternative

The No Action Alternative refers to the continuation of existing conditions of the affected environment, without implementation of the Project. Inclusion of the No Action Alternative is prescribed by the CEQ's NEPA implementing regulations and serves as a benchmark against which Federal actions can be evaluated. Under the No Action Alternative, the additional infrastructure proposed by the Applicant would neither be built nor brought on line and the potential positive or negative environmental impacts identified in the EIS/EIR would not occur. The demand for additional volumes of natural gas could not be satisfied by the Project. Several onshore LNG facilities exist or are being proposed that target the New England market. Proposed onshore and offshore facilities are projects independent of each other (i.e., they are not mutually exclusive); therefore they are not considered to be alternatives to each other. Onshore facilities are discussed under the No Action Alternative, since they could be developed regardless of the outcome of any proposed DWPA application. The NEG Project is discussed in **Section 6**, Cumulative and Other Impacts, as a foreseeable action. Both the Neptune and NEG projects could be licensed by the secretary, they are also not considered to be alternatives to each other. Any LNG project would have an attendant set of environmental consequences.

Similarly, if the Secretary were to deny or postpone the DWPA license application, potential natural gas customers could be forced to seek regulatory approval to use other forms of energy. Other license or Certificate applications concerning proposals to satisfy demand for natural gas might be submitted to the Secretary or Secretary of the Commission, or other means might be used to satisfy the demand for energy in the United States, such as expansion or establishment of onshore LNG import terminals.

As described in **Section 1.2**, projected natural gas demand exceeds the currently available supply. Should the No Action Alternative be adopted, potential customers could select other available energy alternatives, such as oil or coal, or would need to seek traditional non-LNG-derived natural gas to compensate for the reduced availability of natural gas to be supplied by the Project. The No Action

Alternative would avoid the potential for environmental impacts associated with Project construction and operation. Failure to provide additional LNG to the domestic market would cause reliance on other natural gas sources and increased prices or shortages for industrial use and electricity generation. As discussed below, use of other fuel sources could have negative economic or environmental effects, or both, regionally and nationally.

Failing to bring LNG into the region would most likely result in short-term natural gas shortages and increased reliance on other fuel sources (mainly fuel oil) to make up the difference, especially for use in electricity generation. Many natural gas power plants have the option of substituting fuel oil, should natural gas become unavailable or prohibitively expensive. The projected national increase in petroleum product consumption between 2002 and 2025 is similar to that for natural gas. Consequently, there is unlikely to be a surplus of petroleum fuel that could readily provide a cost-effective alternative to natural gas without significant new discoveries of crude oil.

It is possible that existing natural gas infrastructure supplying the proposed market area could be developed in other ways unforeseen at this point, including the further development of natural gas sources in North America and construction of associated pipeline projects. In some cases, potential customers of natural gas could select available energy alternatives such as oil, coal, wind, solar, hydro, or biomass to compensate for the reduced availability of natural gas. It is purely speculative to predict the resulting action that could be taken by the end users of the natural gas supplied by the Project and the associated direct and indirect environmental impacts.

2.1.2.1 Energy Source Alternatives

The insufficient supply of natural gas that could result under the No Action Alternative could lead to fuel substitution, most likely from other fossil fuels such as coal or oil. Natural gas is the cleanest burning fossil fuel. Increased use of other fossil fuels with existing emissions-control technologies would lead to increased emissions of combustion by-products, including carbon dioxide (CO_2), sulfur dioxide (SO_2), and NO_x (**Table 2.1-7**).

Table 2.1-7. Estimated Air Emissions by Fossil Fuel Type for Electric Power Generation

Fossil Fuel Type	CO_2 (lb/kWh)	SO_x (lb/kWh)	NO_x (lb/kWh)
Coal	2.1	0.01	0.008
Oil	1.6	0.01	0.002
Natural Gas	1.0	0.000007	0.002

Source: EIA 2004

Notes: Estimated emissions are based on total emissions and total electrical power production for each fossil fuel type, as reported in USEPA's Annual Energy Review 2003.
lb/kWh – pounds per kilowatt hour

Natural gas combustion generates 34 to 52 percent less CO_2 than conventional fuels such as oil or coal. Other emissions from natural gas combustion are also significantly lower than those from oil or coal. Thus, the use of other fossil fuels in place of natural gas would increase atmospheric pollution and waste volumes, and would incur secondary impacts associated with production (e.g., coal mining and oil drilling), transportation (e.g., oil tankers, rail cars, and pipelines), and refining.

Currently, there are several programs at various stages of research, development, and deployment to convert coal to clean burning gaseous products and to control pollutants, including CO_2 from the direct combustion of coal. Many of the technologies are promising but none have been demonstrated at commercial scales. The potential for these technologies to replace natural gas is unknown.

Other traditional long-term fuel source alternatives to natural gas for electric generation are nuclear power, hydropower production, and development of renewable energy sources. Because of permitting, cost considerations, nuclear waste disposal, and potential public concerns, new sources of nuclear power are unlikely to appear in the near future. It is also unlikely that significant new hydropower sources could be permitted and brought online as a reliable alternative to the LNG provided by the Project, particularly in the northeastern United States.

Although technology is improving and costs are declining for renewable energy (e.g., wind, solar, and biomass), the percentage of national electricity generated from nonhydropower renewable energy sources is projected to increase from 2.2 percent of domestic energy use in 2002 to only 3.7 percent in 2025 (EIA 2004). Several programs are underway to develop methods for generating commercial quantities of hydrogen as a transportation and electricity generating fuel. Consideration has been given to generating hydrogen at remotely sited renewable energy complexes and transporting the hydrogen to high use areas. While this is in the early stages of research, if hydrogen eventually becomes a widely used fuel, then the mechanisms for importing it into the Massachusetts market would involve environmental impacts that cannot be estimated. Consequently, the quantity of energy generated from nonhydropower renewable energy sources is not likely to provide a reasonable alternative to an increased natural gas supply.

Another alternative energy source would be traditional non-LNG-derived natural gas. While natural gas production is important to the overall supply of energy nationally, production levels are not expected to rise in the short term, except from the Arctic region as well as unconventional sources (e.g., shale, tight sands, and coalbed methane) in the Rocky Mountain region. Given a projected increase in natural gas demand in the Rocky Mountain region itself, these unconventional sources would not provide a reasonable alternative to the Project. Likewise, natural gas from the Arctic region is not a reasonable alternative because those supplies alone would be insufficient to meet projected increases in demand.

The National Petroleum Council's (NPC) September 2003 publication, *Balancing Natural Gas Policy*, determined that traditional North American producing areas will provide 75 percent of long-term needs for natural gas in the United States, but will be unable to meet projected demand. The NPC study found that the overall level of indigenous production will be dependent on industry's ability to increase its production of nonconventional gas (i.e., gas from tight formations, shales, and coalbed methane).

2.1.2.2 Energy Conservation Alternatives

Energy conservation and increased efficiency in energy production have been a component of the national energy agenda since the Arab Oil Embargo of 1973. Energy conservation can play a critical role in the future of the United States energy sector, however, growth projections continue to indicate that the demand for energy, and specifically natural gas, will outstrip cost-effective programs designed to stimulate energy conservation. For example, the Oak Ridge National Laboratory analyzed data from the DOE's State Energy Program. The State Energy Program is a federally funded, state-based program administered by the DOE (the only such program administered by the DOE) that provides financial and technical assistance for a variety of energy efficiency and renewable energy activities. The Oak Ridge National Laboratory determined that the program resulted in an estimated annual energy savings of approximately 41 trillion Btu (Schweitzer and Tonn 2005). To put this amount of energy in context, the United States consumed 98 quadrillion Btu of total energy in 2002, roughly 2,400 times the 41 trillion Btu of energy savings reported by the Oak Ridge National Laboratory.

In summary, existing energy conservation programs are unlikely to fully offset the projected growth in demand for energy, and a corresponding demand for natural gas, in the northeastern United States or nationally. Continued economic growth, particularly growth of electricity demand, throughout the United States will lead to increased natural gas use, despite programs to encourage energy conservation. Thus, energy conservation alone would not preclude the need for this Project.

2.1.2.3 Potential LNG Import Facilities

Numerous LNG import terminals are proposed for the northeastern United States and the Canadian Maritimes. Proposed onshore and offshore facilities are projects independent of each other (i.e., they are not mutually exclusive); therefore they are not considered to be alternatives to each other. Onshore facilities are discussed under the No Action Alternative, since they could be developed regardless of the outcome of any proposed DWPA application. The NEG Project is discussed in **Section 6**, Cumulative and Other Impacts, as a foreseeable action. Both the Neptune and NEG projects could be licensed by the secretary, they are also not considered to be alternatives to each other. Any LNG project would have an attendant set of environmental consequences.

In the eastern United States, from Connecticut through northern Maine, seven new LNG terminals are currently proposed. Providence Peak Shaving Plant Expansion, KeySpan LNG's application to upgrade its facility in Providence, Rhode Island, from a storage facility to a marine import terminal, has been denied a license by the FERC and is not, therefore, included in this review. An additional four projects are either proposed or permitted and under construction in eastern Canada. **Table 2.1-8** lists the proposed and permitted LNG terminals in the region. More detailed descriptions of the individual proposals follow.

Broadwater Energy LNG Project (Long Island Sound)

Broadwater Energy proposes to construct and operate an offshore FSRU in Long Island Sound, New York, approximately 14.5 km (9 mi) off the New York shore (FERC Dockets CP06-54-000, CP06-55-000, and CP06-56-000). It would connect to the Iroquois Gas Transmission system about 40 km (25 mi) to the southwest via a subsea pipeline. The first delivery of LNG is forecasted for 2010. This project has been specifically designed to serve the New York and Connecticut markets and would not meet the needs of the Massachusetts/New England market targeted by the Project.

NEG LNG Deepwater Port Application (Massachusetts Bay, Massachusetts)

NEG LNG (USCG Docket 2005-22219) proposes to construct and operate an LNG deepwater port approximately 35 km (22 mi) east of Boston, Massachusetts, in Federal waters approximately 4.8 km (3 mi) from the Neptune Project. The proposed Port, utilizing two submerged unloading buoys, would moor specially designed ships equipped to store, transport, and vaporize LNG. The two buoys would interconnect via a riser, Pipe Line End Manifold, and pipeline with the existing HubLine. The average output would be 400 MMscfd and the ships would moor for 4 to 8 days, depending on vessel size, vaporizer throughput, and market demand. The NEG Deepwater Port License Application was determined to be complete and noticed in the *Federal Register* on September 30, 2005. A Draft EIS/EIR was published on May 19, 2006. NEG estimates project startup for commercial operation in late 2007. Environmental issues associated with the development of this project are identified in the NEG Draft EIS/EIR and as discussed in **Section 6** of this EIS/EIR.

Table 2.1-8. Proposed and Existing Northeastern LNG Terminals as of May 31, 2005

Project/Owner	Location	Natural Gas Send-out	LNG Storage	Status
Crown Landing LLC/BP Energy [l]	Logan Township, New Jersey	1.2 bcfd	450,000 m^3	FERC issued a favorable environmental review on April 28, 2006.
Broadwater Energy LNG/Shell and TransCanada [f]	Long Island Sound, New York	1.0 bcfd	350,000 m^3	NEPA review in progress.
Quoddy Bay LNG/Quoddy Bay LLC and Sipayik Tribal Government [c]	Pleasant Point, Maine	2.0 bcfd	10 bcf	Bureau of Indian Affairs approved lease agreement for project July 2005. FERC pre-filing request approved January 2006.
Downeast LNG/Kestrel Energy Partners, LLC [d]	Robbinston, Maine	0.5 bcfd	160,000 m^3	Pre-filing request approved by FERC January 25, 2006. Town of Robbinston passed referendum supporting project January 2006.
Calais LNG and Cianbro Corporation	Red Beach Village Calais, Maine	Not Available	Not Available	Announced in February 2006.
Dominion Cove Point LNG, LP/Dominion Gas Transmission [k]	Cove Point, Maryland	1.0 bcfd	7.8 bcf	FERC issued a favorable environmental review on April 28, 2006.
AES Battery Rock, LLC [e]	Outer Brewster Island, Massachusetts	Not available	Not available	Project in preliminary stages – requires 2/3 vote by MA legislators for site access before applying for other permits.
Weaver's Cove LNG/Weaver's Cove Energy LLC and Hess LNG [b]	Fall River, Massachusetts	0.4 – 0.8 bcfd	200,000 m^3	FERC approval issued July 2005; FERC decision reaffirmed in January 2006. Appeal filed in the 1st U.S. Circuit Court of Appeals in Boston by project opponents in January 2006.
NEG Energy Bridge LLC/Excelerate Energy LLC [a]	Massachusetts Bay, Massachusetts	0.4 bcfd	Not available	Application deemed complete by USCG in September 2005. NEPA review in progress.
Bear Head LNG/Anadarko Petroleum Corp [g]	Point Tupper, Nova Scotia, Canada	1.0 bcfd	480,000 m^3	Construction suspended. Expected in-service date of 2008.
Canaport LNG/Irving Oil and Reptol YPF [h]	St. John, New Brunswick, Canada	1.0 bcfd	420,000 m^3	Site clearing completed in May 2005. Onshore construction began in Spring 2006. In-service date is 2008.
Cacouna Energy LNG/TransCanada and Petro Canada [i]	Riviere-du-Loup, Quebec, Canada	0.5 bcfd	320,000 m^3	Canadian government announced plans for full environmental review January 2006.
Nova Scotia Project/Keltic Petrochemical and Petrplus International BV [j]	Goldsboro, Nova Scotia, Canada	1.0 bcfd	480,000 m^3	Application submitted.

Sources: [a] Excelerate Energy 2005a, b; NEG 2005; [b] Weaver's Cove 2005; [c] Quoddy 2005a, b; [d] Downeast 2005a, b; [e] The Boston Globe 2005; [f] 70 FR 48698–48701; [g] Anadarko 2005a, b, c; [h] Ocean Resources 2005; Irving Oil 2005; [i] Cacouna undated(a), undated(b); [j] Nova Scotia 2005a, b, c; CNW Group 2005; [k] Dominion 2006; and [l] BP 2003

Outer Brewster Island Terminal (Boston Harbor, Massachusetts)

AES Battery Rock LLC, a subsidiary of AES Corporation, proposes to build an LNG storage and regasification terminal on Outer Brewster Island in Boston Harbor. The island is part of the Boston Harbor Islands National Park Area, a state and national park, approximately 3.2 km (2 mi) from the town of Hull, Massachusetts. The facility would include a new 1.9-km (1.2-mi) undersea pipeline that would transport the gas from the facility to an existing gas line between Beverly and Weymouth, Massachusetts. AES Corporation proposes to build the LNG tanks in shafts quarried 24 m (80 ft) into the island rock, which would limit the visible portions of the structures to about 6 to 9 m (20 to 30 ft) above ground (The Boston Globe 2005).

To develop the island, the AES Corporation would need a two-thirds vote of the Massachusetts Legislature prior to pursuing other Federal and state approvals. The proposal was received with mixed reactions from public interest groups, and issues associated with park use and access, including impacts on recreational boaters and hikers from nearby waters and islands, are being raised. No applications have been filed for this project, so no information on its potential impacts is available. Therefore, with the exception of the consideration given to the project in **Section 6**, Cumulative Impacts, Battery Rock is not considered further in this evaluation.

Weaver's Cove LNG Terminal (Fall River, Massachusetts)

Weaver's Cove Energy, LLC and Mill River, LLC filed an application with FERC on December 19, 2003, for an LNG import terminal and associated pipelines (FERC Docket CP04-36-000). It is situated on a 73-acre site in Fall River, Massachusetts. The proposed facility includes an unloading berth, a 200,000-m^3 storage tank and vaporization equipment for send-out of 400 to 800 MMscfd of natural gas, truck loading stations, and two pipeline segments totaling 11.3 km (6.1 mi) of 24-inch pipeline.

Weaver's Cove Energy, LLC proposed to start construction in mid to late 2005 and be completed within approximately 33 to 36 months, in 2008. FERC issued an approval to construct and operate the terminal on July 15, 2005. Appeals, filed by the City of Fall River, the Rhode Island Attorney General, the Massachusetts Energy Facilities Siting Board, and others, have delayed the process. The appeals were denied on January 19, 2006, in a FERC affirmation of its July 2005 decision. This decision is being appealed in the 1st U.S. Circuit Court of Appeals in Boston by project opponents.

Concern over the Weaver's Cove LNG Terminal includes public safety, the amount of dredging and upland disposal that would be required for the project, and potential impacts on quahog and winter flounder habitat. The U.S. Navy also expressed concern over potential disruptions to the Narragansett Bay Submarine training grounds. State officials and local residents have expressed concern over the number of LNG vessels that would annually traverse the approach from the mouth of Narragansett Bay to the proposed facility and the close proximity of the site to high population areas. To mitigate concerns of potential impacts on the historic Brightman Street Bridge, Weaver's Cove Energy, LLC has proposed the use of smaller LNG tankers to serve the new terminal.

Downeast LNG Project (Robbinston, Maine)

Kestrel Energy Partners, LLC proposes to construct an import terminal in Mill Cove, near the location of where St. Croix River meets Passamaquoddy Bay (FERC Docket PF06-13-000). Proposed project facilities include one 160,000-m^3 LNG storage tank, processing equipment, a new pier, and several small support buildings. A second storage tank might be constructed after operations begin. The proposed facility would transport up to 500 MMscfd to the regional pipeline system.

Downeast's prefiling request was approved by FERC on January 25, 2006, and the project has received a vote of confidence from the people of Robbinston for terminal development. The project anticipates an in-service date of 2010.

The proposed terminal site is approximately 4.8 km (3 mi) from St. Andrews, New Brunswick, Canada, a resort town that derives significant income from whale-watching tours and other water-related activities. St. Andrews has expressed concern over public safety, the industrialization of Passamaquoddy Bay, and impacts on tourism. In February 2006, the Robbinston Planning Board unanimously (5-0) granted the project approvals under the town's Shoreland Zoning Ordinance and a Conditional Land Use Permit for the project's main facility. In addition to the issue of water access, potential issues include impacts on the lobster fishery, aquaculture operations, tourism, and safety relative to the tidal extremes, fogs, and narrow channels of the area.

Quoddy Bay LNG Project (Pleasant Point, Maine)

Quoddy Bay LLC entered into a lease agreement with the Passamaquoddy Tribe at Pleasant Point to build an LNG terminal at Split Route, near Eastport, Maine (FERC Docket PF06-11-000). The project would include storage for up to 10 bcf of LNG with a sendout capacity of 0.5 bcfd. A request for commencement of the pre-filing process was approved by FERC on January 25, 2006. The project developers propose to transport gas from the facility in the Maritimes & Northeast Pipeline, although at this time there have been no formal discussions with Maritimes & Northeast.

Given the proposed terminal location, LNG tankers heading into and out of the port might have to cross through Canadian waters. This project faces the same issue of Canadian water access for LNG transport as the Downeast LNG Project. In addition to the issue of water access, potential issues include impacts on the lobster fishery, aquaculture operations, tourism, and safety relative to the tidal extremes, fogs, and narrow channels of the area.

Calais LNG Terminal (Calais, Maine)

A joint effort between Calais LNG and its business partner, Cianbro Corporation (and owned by the Passamaquoddy tribe) proposes to construct an LNG terminal on the St. Croix River between Devil's Head and St. Croix Island in the Red Beach area of Calais, Maine. The location is across from an active gravel pit and the Canadian shipping port at Bayside, New Brunswick. The project would include construction of a 518-m (1,700-ft) jetty, two large storage tanks, and a pipeline that would transport the gas to Baileyville, Maine, where it would connect with an interstate pipeline. The project was announced before a joint meeting of the Calais City Council and the planning board in early February 2006, and is in the early stages of development.

As proposed, LNG tankers accessing the site would have to navigate Head Harbour Passage near Campobello Island, New Brunswick, Canada, before reaching the port in Maine. Issues of water rights-of-way have been raised. Regional Canadian officials maintain that they have the right to block passage of ships into their sovereign waters and Federal lawyers in the United States and Canada are reviewing relevant maritime laws. In addition to the issue of water access, potential issues include impacts on the lobster fishery, aquaculture operations, tourism, and safety relative to the tidal extremes, fogs, and narrow channels of the area.

Bear Head LNG (Point Tupper, Nova Scotia, Canada)

The development would include marine offloading, LNG storage and regasification facilities to deliver gas into the Maritimes & Northeast Pipeline, which services the Eastern Canada and Northeast

U.S. gas markets. The terminal was expected to be in commercial operation with 750 MMscfd to 1 bcfd of sendout capacity in 2008, but construction has been suspended pending resolution of LNG supply issues.

Canaport LNG (St. John, New Brunswick, Canada)

Site clearing was completed for this facility in May 2005, and onshore construction began in spring 2006. The facility is scheduled to be operational in 2008 initially delivering 1 bcfd of regasified LNG to the market. M&NE pipeline has filed a request with FERC to expand capacity to accommodate natural gas deliveries from the Canaport Project in the New England area.

Cacouna Energy LNG

TransCanada Corporation and Petro-Canada propose to develop a Cacouna Energy LNG facility in Gros Cacouna, Quebec. The proposed facility would be capable of receiving, storing, and regasifying imported LNG with an average annual sendout capacity of approximately 500 MMscfd of natural gas. The development is intended to help meet the energy needs of consumers in North America. No dredging for carrier access is necessary at this site which is in an area of low seismic activity and already contains some industrial development.

The EIS/EIR for this project was filed with provincial regulators in May 2005 and regulatory approvals are anticipated by the end of 2006. Construction is scheduled between 2007 and 2009, and terminal operations are anticipated to start up by the end of 2009 or early 2010.

Nova Scotia Project (Goldboro, Nova Scotia, Canada)

The proposed Nova Scotia Project would include three LNG storage tanks with a gross capacity of 160,000 m^3 each, providing a sendout capacity of 1.0 bcfd. The site has sufficient space and utilities available to add three additional tanks for an increased total sendout capacity of 2.0 bcfd. The terminal is proposed to have the ability to receive LNGCs with capacities ranging from 75,000 m^3 to the largest planned LNGCs (250,000 m^3). The project's regasification terminal would be adjacent to the Maritimes & Northeast Pipeline intake station at the Sable Island Gas Plant in Goldboro, Nova Scotia.

Crown Landing (Logan Township, New Jersey)

The proposed Crown Landing LNG terminal would reside on a 175-acre parcel on the Delaware River. This facility has a planned capacity of 1.2 bcfd. To accommodate LNG ships and the berthing pier, a total of 800,000 cubic yards would need to be dredged in the Delaware River. The Crown Landing LNG terminal would tie in into the Columbia, Transco, and Texas Eastern pipelines which would help distribute natural gas to the Mid-Atlantic. On June 15, 2006, FERC gave approval for the construction and operation of the Crown Landing LNG (CL LNG 2004).

Cove Point Expansion (Lusby, Maryland)

Dominion Energy has proposed to double the capacity of its existing Dominion Cove Point LNG facility. The expansion would raise the throughput capacity of the existing facility from 1.0 to 1.8 bcfd and the storage capacity would increase from 7.8 to 14.5 bcf storage. This project expansion would help to provide more natural gas to the Northeast and Mid-Atlantic. On August 18, 2006, FERC issued its approval for the expansion project (CL LNG 2004).

2.1.2.4 Comparison of Alternatives – Safety and Environmental Considerations

Of these proposed facilities, Broadwater, Crown Landing, and Cove Point Expansion will be located in areas that would not be able to serve the Massachusetts market. As discussed in **Section 1.2.3**, the natural gas pipelines supplying New England from the south and west are limited. Competition for available supplies from the Mid-Atlantic states has limited the availability of additional gas to Massachusetts. The projects proposed for New York and New Jersey are unlikely to contribute significant quantities of gas to Massachusetts and are therefore not evaluated further. Of the remaining proposed projects in the New England states and eastern Canada, the potential safety and environmental impacts associated with these facilities might be similar to or different than the impacts associated with Neptune. To facilitate evaluation of the impacts of these facilities, five were selected as representative and evaluated in more depth. These are

- Weaver's Cove (Onshore Massachusetts)
- Quoddy Bay and Downeast LNG (Onshore Maine)
- Canaport LNG and Bear Head LNG (Onshore Canada).

A summary of the onshore site characteristics, descriptions of the facility safety, and environmental issues for Weaver's Cove LNG, Quoddy Bay, Downeast LNG, Bear Head, and Canaport are shown in **Table 2.1-9**.

Table 2.1-9. Summary Comparative Onshore Site Characteristics

	Weaver's Cove LNG	Quoddy Bay LNG	Downeast LNG	Bear Head LNG	Canaport LNG
Exclusion zones in site footprint	303-m (993-ft) thermal radiation exclusion zone. Assumed to fall outside of site footprint.	303-m (993-ft) thermal radiation exclusion zone. Assumed to fall outside of site footprint (assumed from Weaver's Cove).	303-m (993-ft) thermal radiation exclusion zone. Accommodated within site footprint (assumed from Weaver's Cove).	Not found.	Not found.
Residential density	12,000 people live within 1 mile of proposed LNG site.	448 people/mi^2 Eastport, ME.	19 people/mi^2 Robbinston, ME.	43 people/mi^2 average in Nova Scotia.	819 people/mi^2 in Saint John, New Brunswick
Berth location and safety	Pier within industrial zone.	396-m (1,300-ft) long pier, two berths with unloading platforms. Each berth will be approximately 320 m (1,050 ft) long.	Single unloading berth with 1,177 m (3,862 ft) long pier.	46 m (150 ft) long, with a ship draft of 14 m (45 ft). Buffer zone 351 m (1,150 ft) wide.	Pier would be 351 m (1,150 ft) for off-loading. Tankers of various uses may dock at pier without occurrence.

Table 2.1-9. Summary Comparative Onshore Site Characteristics (continued)

	Bear Head	Canaport	Quoddy Bay	Downeast LNG	Weaver's Cove LNG
Transit safety	Route passes under Braga Bridge. Passes medium density town of Fall River.	No densely populated areas along transit route.	No densely populated areas along transit route.	No densely populated areas along transit route.	Populations won't be significantly affected by transit between Mispec and Saint John.
Interference with other marine uses	Safety zones would disrupt Taunton River and Mount Hope Bay traffic for approximately 60 minutes as vessels travel to and from site.	Temporary security zone around each ship which might preclude some marine access, but would only last 10 minutes as ships would travel at 6 knots.	No public boat ramps or facilities, some boating activities will be restricted during transit and offloading.	Effects on harbor access and local fishing grounds are not expected or are presumed to be relatively short in duration during construction and operation.	Exclusion zone or public vessel advisories will be used to ensure that public marine watercraft are not in the vicinity of LNG tankers.
Maximum population potentially impacted by vessel transit	Transit is not through populated areas.	Transit is not through populated areas.	Ten minute delay expected for residential and commercial fishermen, whale watchers.	Ten homes within 0.8 km (0.5 mi) radius of docked ships. Populations won't be significantly affected by transit.	Transit route follows along Fall River and Somerset shoreline.
Population potentially impacted at tanker berth	No residents at tanker berth. Zoned as an industrial area.	Relative size of berth, coupled with existing structures, will have no significant impact on existing populations.	Believed that no residents at tanker berth location.	Believed that no residents at tanker berth location.	Approximately 616 people reside within 671-m (2,200-ft) radius. Within 1,463-m (4,800-ft) radius, approximately 3,167 people reside.
Credible worst-case population potentially impacted by vessel transit	None expected.	Populations won't be significantly affected by transit between Mispec and Saint John.	None expected.	None expected.	Transit route through populated areas and under commuter bridges.

Table 2.1-9. Summary Comparative Onshore Site Characteristics (continued)

	Bear Head	Canaport	Quoddy Bay	Downeast LNG	Weaver's Cove LNG
Credible worst-case population potentially impacted at tanker berth	No residents at tanker berth. No adverse long-term effect on sea life and marine mammals.	Minimal impact, but local fish and aquatic mammals might suffer some impact in a worst case scenario.	Minimal impact, but local fish and aquatic mammals might be impacted.	Minimal impact, but local fish and aquatic mammals might be impacted.	About 3,000 residents would be impacted. Local fish and aquatic mammals might be impacted.
Dredging volume	Not needed.	Approximately 25,000 to 30,000 m^3 to be swept and sidecast.	Not needed.	Not needed.	2.6 million cubic yards of sediment, which would be reused as fill on site.
Dredging footprint	None.	Approximately 9,375 m^2	None.	None.	Approximately 975,000 yd^2.
Dredge sediment contamination	None.	Slight, with effect on native mollusks and sea life.	None.	None	Unknown.
Eggs	Herring, cod, haddock, pollock, silver hake, white hake, sand lance, mackerel, redfish, cusk, yellowtail, north shrimp, lobster, crab, and scallops. Specific species are designated "Atlantic."	Atlantic salmon, Atlantic wolfish, Atlantic cod, North Atlantic right whale, mussels, rock crab, and shortnose sturgeon.	Winter flounder, yellowtail flounder, windowpane flounder, American plaice, ocean pout, Atlantic halibut, and Atlantic sea scallops.	Winter flounder, yellowtail flounder, windowpane flounder, American plaice, ocean pout, Atlantic halibut, and Atlantic sea scallops.	Winter flounder, yellowtail flounder, windowpane flounder, American plaice, ocean pout, Atlantic halibut, Atlantic sea scallops, and Atlantic lobster.

Table 2.1-9. Summary Comparative Onshore Site Characteristics (continued)

	Bear Head	Canaport	Quoddy Bay	Downeast LNG	Weaver's Cove LNG
Larvae	Herring, cod, haddock, pollock, silver hake, white hake, sand lance, mackerel, redfish, cusk, yellowtail, north shrimp, lobster, crab, and scallops. Specific species are designated "Atlantic."	Atlantic salmon, Atlantic wolfish, Atlantic cod, North Atlantic right whale, mussels, rock crab, and shortnose sturgeon.	Same as "Eggs," plus Atlantic cod, pollock, and Atlantic sea herring.	Same as "Eggs," plus Atlantic cod, pollock, and Atlantic sea herring.	Same as "Eggs," plus Atlantic cod, Atlantic salmon, Atlantic sea herring, and blueback herring.
Juveniles	Herring, cod, haddock, pollock, silver hake, white hake, sand lance, mackerel, redfish, cusk, yellowtail, north shrimp, lobster, crab, and scallops. Specific species are designated "Atlantic."	Atlantic salmon, Atlantic wolfish, Atlantic cod, North Atlantic right whale, mussels, rock crab, and shortnose sturgeon.	Atlantic salmon, Atlantic cod, pollock, whiting, red hake, white hake, winter flounder, windowpane flounder, American plaice, ocean pout, Atlantic halibut, Atlantic sea scallops, and Atlantic sea herring.	Atlantic salmon, Atlantic cod, pollock, whiting, red hake, white hake, winter flounder, windowpane flounder, American plaice, ocean pout, Atlantic halibut, Atlantic sea scallops, and Atlantic sea herring.	Atlantic salmon, Atlantic cod, pollock, whiting, red hake, white hake, winter flounder, windowpane flounder, blueback herring, Atlantic halibut, Atlantic lobster, and Atlantic sea herring.
Adults	Herring, cod, haddock, pollock, silver hake, white hake, sand lance, mackerel, redfish, cusk, yellowtail, north shrimp, lobster, crab, and scallops. Specific species are designated "Atlantic."	Atlantic salmon, Atlantic wolfish, Atlantic cod, North Atlantic right whale, mussels, rock crab, and shortnose sturgeon.	Atlantic salmon, Atlantic cod, pollock, whiting, red hake, white hake, winter flounder, windowpane flounder, American plaice, ocean pout, Atlantic halibut, Atlantic sea herring, and Atlantic mackerel.	Atlantic salmon, Atlantic cod, pollock, whiting, red hake, white hake, winter flounder, windowpane flounder, American plaice, ocean pout, Atlantic halibut, Atlantic sea herring, and Atlantic mackerel.	Atlantic salmon, Atlantic cod, pollock, whiting, red hake, white hake, winter flounder, windowpane flounder, blueback herring, Atlantic halibut, Atlantic lobster, Atlantic sea herring, and Atlantic mackerel.

Table 2.1-9. Summary Comparative Onshore Site Characteristics (continued)

	Bear Head	Canaport	Quoddy Bay	Downeast LNG	Weaver's Cove LNG
Rare/Endangered species present	No endangered, rare, or threatened species in vicinity.	Atlantic salmon, Atlantic wolfish, Atlantic cod, North Atlantic right whale, mussels, rock crab, and shortnose sturgeon.	No endangered, rare, or threatened species in vicinity.	No endangered, rare, or threatened species in vicinity.	At proposed site, none. In Mount Hope Bay, Kemp's Ridley sea turtle.
Pipeline construction acreage	239 acres.	646 acres.	246 acres	176 acres	42 acres
Highway access for construction traffic	Accessible by Bear Island Road	Accessible by Bay Side Drive, Red Head Road, and the Canaport Access Road.	Roads existing; distances unknown	Accessible by Route 1.	Limited highway access to proposed site.
Marine transit distance (including 3-mile mark from provincial waters).	Approximately 35 km (22 mi).	Approximately 35 km (22 mi).	Approximately 17.7 km (11 mi).	Approximately 74 km (46 mi).	Approximately 34 km (21 mi).
Site acreage	160 acres	654 acres.	42 acres	80 acres	73 acres
Storage tank size	2 tanks 180,000 m^3 (Phase I with an addition tank for Phase II when market conditions are appropriate).	3 tanks, 140,000 m^3.	3 tanks, 160,000 m^3.	1 tank, 160,000 m^3.	1 tank, 200,000 m^3.
Pipeline connection distances to Maritime & Northeast Pipeline.	Approximately 124 km (77 mi).	Approximately 146 km (91 mi).	57.6-km (35.8 mi) -long natural gas sendout pipeline.	Approximately 48 km (30 mi).	Approximately 113 km (70 mi).
Average throughput				0.5 bcfd.	
Maximum throughput	0.5 bcfd	2.0 bcfd.	2.0 bcfd	1.0 bcfd.	0.4 to 0.8 bcfd.
LNG trucking	NA-transfer will occur via shipping vessels.	NA-transfer will occur via shipping vessels.	NA-transfer will occur via shipping vessels.	NA-transfer will occur via shipping vessels.	Approximately 100 trucks per day.

Weaver's Cover LNG

Safety Considerations

Weaver's Cove Energy, LLC is developing an LNG terminal on an approximately 73 acre site on the Taunton River in the City of Fall River, Massachusetts. The site previously supported a marine terminal for petroleum product receipt, storage, and distribution. Mill River Pipeline, LLC is proposing to construct two new lateral pipelines that would facilitate the downstream delivery of re-gasified LNG to the existing interstate pipeline network.

The Thermal Radiation Exclusion Zone for spill of LNG extends beyond the site boundary. FERC has required the applicant to demonstrate control over the exclusion area. LNGCs would traverse the Narragansett Bay and Taunton River, requiring passage under highway bridges. Exclusion areas would be enforced around LNGCs in transit, and bridges would be closed during transits. There are approximately 12,000 people living within 1 mile of the proposed terminal site. LNG would be dispersed from the facility in trucks to peak shaving regasification facilities.

Environmental Considerations

The proposed site is composed of 73 acres zoned for industrial use. Construction of the pipeline would have minimal impacts on the Taunton River and its surrounding wetlands. Approximately 2.6 million cubic yards of sediment would be dredged, creating a footprint of approximately 975,000 square yards. Sediment would be used as fill onsite during construction, and contaminated sediments from dredging at site and in the river channel would be resuspended. The impact on the surrounding wetlands would require the fill of 0.04 acres of estuarine salt marsh, 0.94 acres of intertidal habitat, and 0.19 acres of subtidal habitat. These impacts would be mitigated by the creation or restoration of 0.18 acres of freshwater wetland onsite, 0.18 acres of freshwater wetland at an upland site, and restoration to salt marsh of 0.13 acres of tidal creek.

During construction, there would be a temporary disturbance of 191 acres of subtidal habitat by dredging. Permanent clearing of 10.7 acres of forest land, disturbance of 5.1 acres of vegetated open land, and disturbance of 56.6 acres during pipeline construction are expected, as well. Time-of-year restrictions on in-water construction would be used to offset and mitigate for the loss of intertidal and salt marsh areas along with the loss of winter flounder spawning grounds. LNGC safety zones would disrupt river traffic for approximately 60 minutes as it transited to and from the site. Threatened and Endangered marine mammals and sea turtles species face potential impact from LNGC transits through habitat. Mitigation has been proposed to alleviate these impacts. Air quality would be maintained and operational emissions minimized by adhering to the use of SCR. With respect to noise, there would be a temporary increase in noise during construction, and operational noise would be kept below a threshold of 55 dBA.

Quoddy Bay LNG

Safety Considerations

The proposed site for Quoddy Bay LNG would consist of 42 acres on the Passamaquoddy Tribal Reservation in Pleasant Point, Maine. The closest city is Eastport, which has a population density of 448 people per square mile. The import facility will consist of a 1,300-ft pier, 2 berths with unloading platforms, and a process platform. Each berth will be approximately 1,050 feet long, running perpendicular to the pier. The sendout capacity of this facility would be 2.0 bcfd (Quoddy Bay 2006).

During transit there would be a temporary security zone around each ship. This security zone would likely be at least 500 yards. No land-based areas would be affected by the security zones during transit. The security zones could preclude some marine access to the bay, but this impediment would last only 10 minutes as ships would be traveling approximately 6 knots (Quoddy Bay 2006) within the affected area. [The thermal radiation exclusion zone for this project has been estimated based on the Weaver's Cove Energy LNG Project.] Based on these assumptions, the thermal radiation exclusion zone on land would be 71 acres (0.1 mi^2), which could have the potential to affect approximately four people based on the population density of Eastport. The passage route for LNG vessels has been determined to have adequate depth and minimal boat congestion on the western edge of Passamaquoddy Bay (TRC 2005). There are no known areas with heavy marine boat traffic that lie along the intended route of this project (TRC 2005). In addition, no high-density residential areas lie along the vessel route. Tugs will be assisting the LNG tankers through their transit route to assist service to the proposed facility.

During the first phase of operation, regasifying will occur directly from the ship to the sendout pipeline. It could take up to 3 days to unload one ship with 2 to 3 ships expected per week (Quoddy Bay 2006). Once the project site is fully operational, it will take approximately 12 hours to unload the LNG and transfer it to the storage facility. This approximates to 180 ships annually (Quoddy Bay 2006).

Environmental Considerations

There is no associated dredging required for the proposed project. No threatened or endangered species habitat is known to exist in the immediate vicinity of the proposed site. There are many environmentally sensitive areas in the vicinity of the project area which include bird nesting sites, eelgrass beds, seal pupping ledges, and rich clam and oyster beds (TRC 2005). Other wildlife in this area of concern includes porpoises, seals, bald eagles, osprey, ducks, and many types of sea birds making their home in the waters of Head Harbor Passage and Friar Road (TRC 2005).

Impacts on fish and marine wildlife are unknown. Security zones are not expected to significantly impact local fishing boats as the approximate security zone would be 500 yards and would only affect a marine area for an estimated 10 minutes. Some fishing vessels would be redirected to avoid collisions with LNG tankers (Quoddy Bay 2006).

The lateral pipeline is approximately 56 km (35 mi) in length, and would extend from Perry to Princeton, where it will meet the Maritimes & Northeast Pipeline (Quoddy Bay 2006). The lateral pipeline would result in 246 acres of impacts. Impacts on the areas along the lateral pipeline are unknown at this time but blasting could be used to help trench the pipeline at 0.9 to 1.5 m (3 to 5 ft) below the surface. There is little chance of wetland disturbance during construction of the 40 km (25 mi) lateral. To accommodate this project, the Northeast Maritimes project would be required to add at least 5 compressor stations resulting in approximately 12 acres of impacts and build a 2.7-km (1.7-mi) looping project resulting in approximately 2.5 acres of additional impacts.

Project details are unavailable at this time, and impacts have been generalized through desktop surveys.

Downeast LNG

Safety Considerations

The Downeast LNG site offers a remote location in Robbinston, Maine, in Washington County near the intersection of the St. Croix River and Passamaquoddy Bay. The proposed site would occupy 80 acres with 47 acres dedicated for the facility and a 33-acre buffer. There are approximately 20 inhabited homes within a 0.8-km (0.5-mi) radius of the proposed facility and approximately 10 inhabited homes within a 0.8-km (0.5-mi) radius of a possible docked ship; the population density is estimated at 19 people per square mile (Downeast LNG 2005a). The thermal radiation exclusion zone is based on the Weaver's Cove Energy LNG Project because of unavailable information for Downeast LNG. Based on these assumptions the thermal radiation exclusion zone on land would be 71 acres (0.1 mi^2) which would not have the potential to affect adjacent populations. There will be no trucking of LNG that could affect traffic on Route 1 (the main highway access to Robbinston), and few traffic concerns would arise from the proposed project. Although tides can be quite high in the area, they are not expected to be a safety concern with docking and offloading.

The sendout capacity of this facility will be 0.5 bcfd (Downeast LNG 2005a). The site area is not routinely used for water-related activities and there are no public boat ramps or facilities in the affected area. Some water activities will be restricted during transit and offloading of LNG because of the security zone which is estimated to be at least 500 yards. Ship transit from Head Harbor Passage to the pier is expected to take less than 2 hours, and offloading would take about 12 to 14 hours (Downeast LNG 2005a). The ship transit route would require passing through Canadian waters then through Passamaquoddy Bay and would not pass under any bridges or have the possibility to pass through densely populated areas.

Environmental Considerations

There is no associated dredging required for the proposed project. There is adequate depth in the St. Croix River and an ample turning radius of 1.2 km (0.75 mi) for LNG ships. Therefore there will be no dredging or resuspension of contaminated sediments. No threatened or endangered species or habitat is known to exist in the immediate vicinity of the proposed site. The presence of wading and shore birds is expected, but the project is not expected to have effects on these species based on the analysis of similar pier LNG projects (Downeast LNG 2005b). There is Essential Fish Habitat (EFH) for several species of fish in the area affected by the proposed project (see **Table 2.1-9**). Effects on these fish populations are unknown. There is limited fishery activity in the immediate pier area and there is no indication that ship traffic would affect fishing resources (Downeast LNG 2005b).

At least 40 km (25 mi) in pipeline would be constructed to tie in to the Northeast Maritimes Pipeline system along the most direct path, resulting in approximately 176 acres of impacts. The constructed lateral would cross the Moosehorn National Wildlife Refuge for 12 km (7.5 mi), resulting in approximately 52.8 acres of impacts. Preliminary surveying of the lateral pipeline indicated that approximately 19 acres of wetlands occur in the construction Right of Way. This acreage total could be reduced during the final routing stages to alleviate impacts on wetlands (Saint John 2006).

Some project details are unavailable at this time, and impacts have been generalized through desktop surveys.

Canaport LNG

Safety Considerations

The Canaport LNG project is being built as part of the pre-existing Irving Canaport facility, which has operated as a deepwater oil terminal since the 1970s. The LNG facility is being built near St. John, New Brunswick. Upon completion, the facility will feature three storage tanks with a capacity of 140,000 m^3 each. The facility will have a sendout capacity of 1.0 bcfd (Irving 2004). The pier from the LNG facility would extend approximately 299 m (980 ft) from shore to depths of 25 m (82 ft) (Irving 2004). Due to the remote location of the facility, there is a low residential density near the industrial park.

Red Head Road services the Irving Canaport facility. The LNG terminal would be built in a transit area between Mispec and Saint John, where there is an increase in summer recreational fishing and boating. Navigation in the shipping lanes for LNG tankers would be compounded by existing traffic from ships known as "Very Large Crude Carriers," which offload at the existing Irving facility (Irving 2004). The probability of a vessel collision near the vicinity of the loading dock or pier is considered low (Irving 2004). The Canadian Coast Guard coordinates all vessel movements within the harbor and would make certain that appropriate communication between vessels is maintained (Irving 2004). To protect human health and safety, a detailed Emergency Response plan will be prepared according to industry guidelines.

Environmental Considerations

The Canaport LNG terminal would require approximately 25,000 to 30,000 m^3 of river bottom to be sidecast and swept to accommodate LNG ships. Possible contamination from sidecasting and sweeping activities is unknown from expansion of the channel. There are eight species that were determined to be in the vicinity of this project that are listed by the Committee on the Status of Endangered Wildlife in Canada. These species include four fish (Atlantic salmon, Atlantic cod, Atlantic wolfish, shortnose sturgeon), three mammals (blue whale, North Atlantic right whale, harbor porpoise), and one bird (Harlequin Duck) (Irving 2004). The wetlands are on private property already owned by the facility and are of limited public use. They do not belong to any protected area, park, or sanctuary (Irving 2004).

No blasting is expected to occur below the water line or within the intertidal zone. It is expected to occur for construction of the road down to the pier and for the pier trestle itself. This blasting could cause direct mortality of land and sea organisms while destroying adjacent fish habitat. These effects will be short in duration during construction and will not be permanent.

The lateral pipeline would travel 148 km (92 mi) to connect to the Northeast Maritimes Pipeline. The area of impact is approximately 646 acres. There was one ecologically significant wetland that was avoided during siting of this project. There would be minimal disturbance of wetlands from this project, with no wetland greater than 2.5 acres that would be affected by the footprint of this project (Irving 2004). When possible, the applicant will take measures to mitigate impacts on these wetlands.

Bear Head LNG

Safety Considerations

The Bear Head LNG project was under construction in the Point Tupper/Bear Head Industrial Park in Richmond County, Nova Scotia but construction was suspended. This 160-acre project site is in a remote location on the Strait of Canso. The LNG terminal is being designed to safely berth LNG vessels with a 250,000-m^3 capacity and would have a total output capacity of 1.0 bcfd (ANEI 2004). The proposed site is an industrial park with no residents within the 1,150 ft tanker berth buffer zone (ANEI 2004). Because the area is in an industrial zone, there are no small towns or communities within approximately 2.3 km (1.4 mi) of the project site. Adjacent populations would not be affected by the heat radiation level from the ignited cloud of a grounded ship (TRC 2005, ANEI 2004). There is no planned trucking of LNG and the site will be serviced by Industrial Park Road and Bear Island Road (ANEI 2004).

The probability of vessel collision is low due to the established shipping lanes and pilotage requirements when docking. The facility is in compliance with all Federal safety standards to prevent vessel accidents. In addition, a Facility Emergency Response and Contingency Plan for the LNG

Terminal will be prepared and updated as needed to respond to possible vessel accidents and other emergencies (ANEI 2004).

Environmental Considerations

The Strait of Canso has a deep enough channel (approximately 18 m [60 ft]) to avoid dredging. The water basin is wide enough to allow ships enough of a turning radius without man-made expansions necessary. Results of field surveys suggest that it is unlikely that any rare mammal species or sensitive mammal habitat are present in the study area. As such, no significant Project related adverse effects on rare mammals or sensitive mammal habitat are anticipated (ANEI 2004).

Effects on harbor access and local fishing grounds are not expected or are presumed to be relatively short in duration (ANEI 2004). The areas within the terminal footprint are not known to have importance for fish eggs and larvae (ANEI 2004).

The lateral pipeline to the Maritimes Northeast Pipeline would impact approximately 239 acres along the 55-km (34-mi) pipeline. There are six wetlands that are contained within the project boundary, of which five would be impacted by the facility (ANEI 2004). Two of these wetlands would be partially filled which could affect the hydrology and sedimentation. Two others would have a security fence built through them which would temporarily disturb the wetland. These activities are not expected to significantly alter the functionality of these four affected wetlands. One of the wetlands could be significantly impacted by road and other construction activities (ANEI 2004). When possible, the applicant would use best management practices to mitigate impacts on these wetlands.

2.2 Maritime & Northeast Pipeline Expansion

The Maritimes & Northeast (M&NE) Pipeline would require expansion to handle increased capacity from one or more of the proposed LNG facilities in the Northeast United States and Canada (EIA 2006c). Based on information filed with FERC by M&NE for expansions to support accommodating natural gas from one project (Canaport, FERC Docket CP02-78-000) and two projects (Canaport and Bear Head, FERC Docket PF05-17), the following summaries of environmental impacts were developed. The M&NE expansions would be required to accommodate one or two of the onshore projects in Maine or Canada evaluated above, and the environmental impacts would be additive to the impacts for each of the individual LNG projects.

2.2.1 Environmental Considerations of One LNG Project

M&NE expansion would be required to handle increased capacity from the Canaport LNG facility. This expansion would be required to handle increased capacity from the one proposed LNG facility (EIA 2006c). The expansion would require a 2.7 km (1.7 mi) 30 inch pipeline looping project. The looping project is based out of the town of Baileyville, Maine, and is known as the Baileyville Loop.

Approximately 22.4 acres would be temporarily affected by the proposed pipeline project. Of that, approximately 5.24 acres would be permanently lost. The total amount of temporarily affected wetlands for the Baileyville Loop stands at 48.513 acres. Of this total, 2 acres of wetlands would be permanently lost (FERC 2001). After consultations with government agencies, specifically the Maine office of the Department of the Interior and the Massachusetts Division of Fisheries and Wildlife, it was found that no threatened or endangered species are known to occur within the project area. The only noted exceptions are populations of transient bald eagles (FERC 2002).

2.2.2 Environmental Considerations of Two or More LNG Projects

Additional M&NE expansion would be required to handle increased capacity from a second of the proposed projects above (EIA 2006c). The M&NE Phase IV expansion would include the installation and construction of five new compressor stations, upgrades to two existing compressor stations, and construction of 131 miles of additional pipeline loop in Maine and Massachusetts. During construction of the five new compressor stations, 1,623.7 acres would be affected temporarily. Of that, 442.1 acres would be permanently affected (FERC 2006). The project also calls for the expansion of two existing compressor stations.

Construction of the pipeline loops would impact 1,982.2 acres. Of that 526 acres would be permanently affected. An additional 119.6 acres would be impacted temporarily by construction of other above ground facilities such as meter and valve stations. 69.7 acres would be permanent.

Temporary and permanent wetland impacts would be expected for construction of each new compressor station, expansion of the existing compressor stations, and installation of new aboveground facilities such as meter and valve stations, but the exact acreage is unknown. Temporary wetland impacts would be expected for pipeline construction through wetland and groundwater areas, but the exact acreage is not known (FERC 2006). Animals would experience a slight loss of habitat as areas would be cleared, but the initial impact would be small. Interagency field visits of streams have resulted in the identification of the Atlantic Salmon as a species of concern. Consultation with Federal and state agencies to further identify Federal and state listed threatened or endangered species would be conducted if the expansion project is required. Information on threatened and endangered species that was developed in earlier projects along the M&NE rights of way indicated the presence of listed species or habitat for listed species. Specific information for this expansion is not available (FERC 2006). Temporary impacts to vegetation would be expected in order to allow equipment access during construction. These impacts would be expected to be short-term in nature, and the land contours will be returned to preconstruction grade or better. Erosion control measures would be to be enacted within 10 days of backfilling trenches in order to minimize environmental damage. Air emissions from construction would comply with area air quality regulations. The five new compressor stations would include low-NO_x combustors to reduce air emissions (FERC 2006). Acoustically treated metal siding would be used to minimize radiated noise from the compressor stations. Noise levels would create little impact on the surrounding area's flora and fauna (M&NE 2006).

2.3 Detailed Description of the Project

2.3.1 Overview

The Applicant proposes to construct, own, and operate a deepwater port, named Neptune, in the Federal waters of the OCS in blocks NK 19-04 6525 and NK 19-04 6575, approximately 35 km (22 mi) northeast of Boston, Massachusetts, in a water depth of approximately 76.2 m (250 ft). The proposed location of the Port is shown in **Figure 2.3-1**, and a site plan of the Port is shown in **Figure 2.3-2**. No onshore components are associated with the Port.

The Port would be capable of mooring SRVs with a capacity of approximately 140,000 m^3. Up to two SRVs would temporarily moor at the Port by means of a submerged unloading buoy system. Two unloading buoys would be separated by a distance of approximately 3.7 km (2.3 mi). The unloading buoys would moor each SRV on location throughout the unloading cycle. Each unloading buoy would have eight mooring lines consisting of wire rope and chain. The mooring lines would connect each

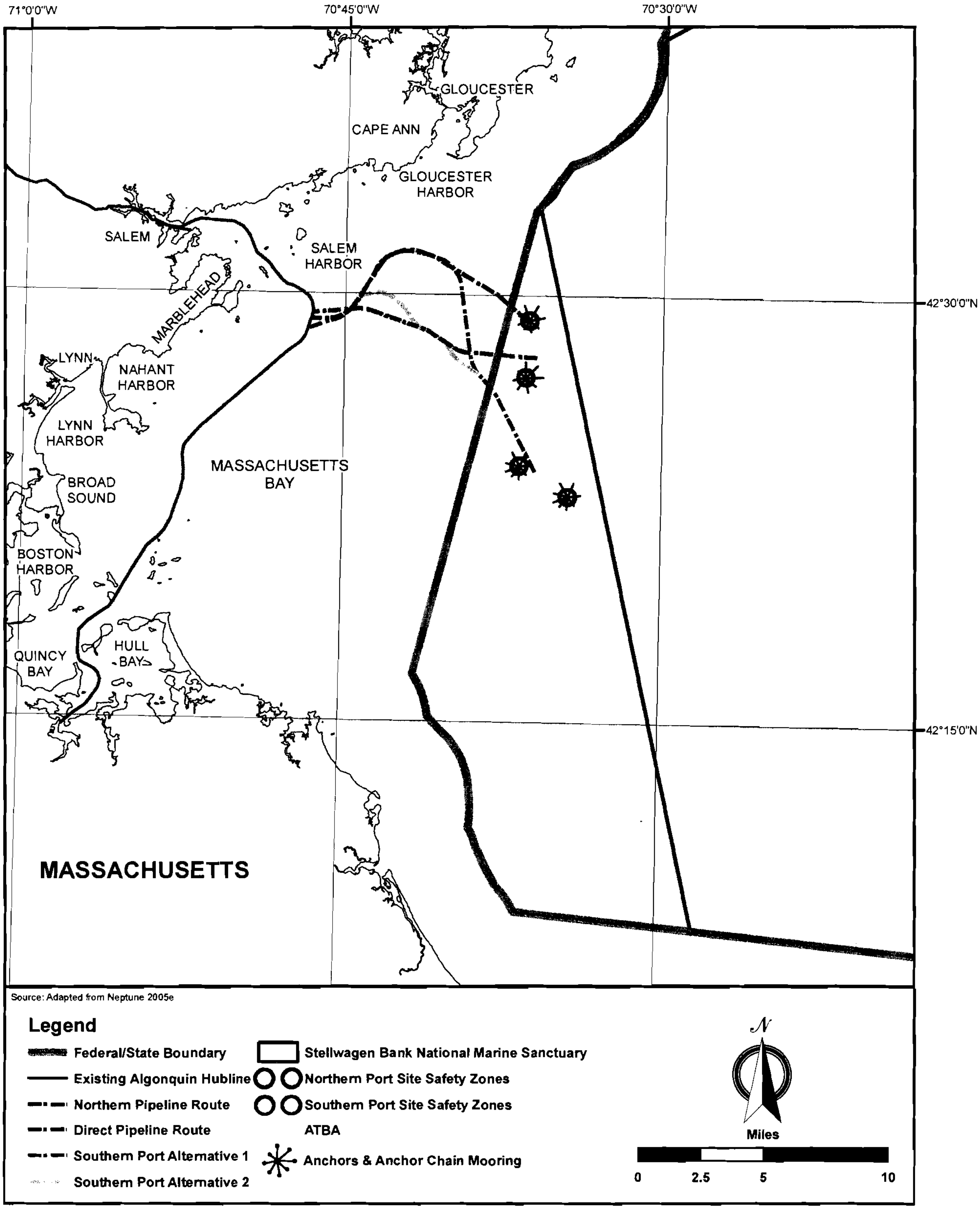
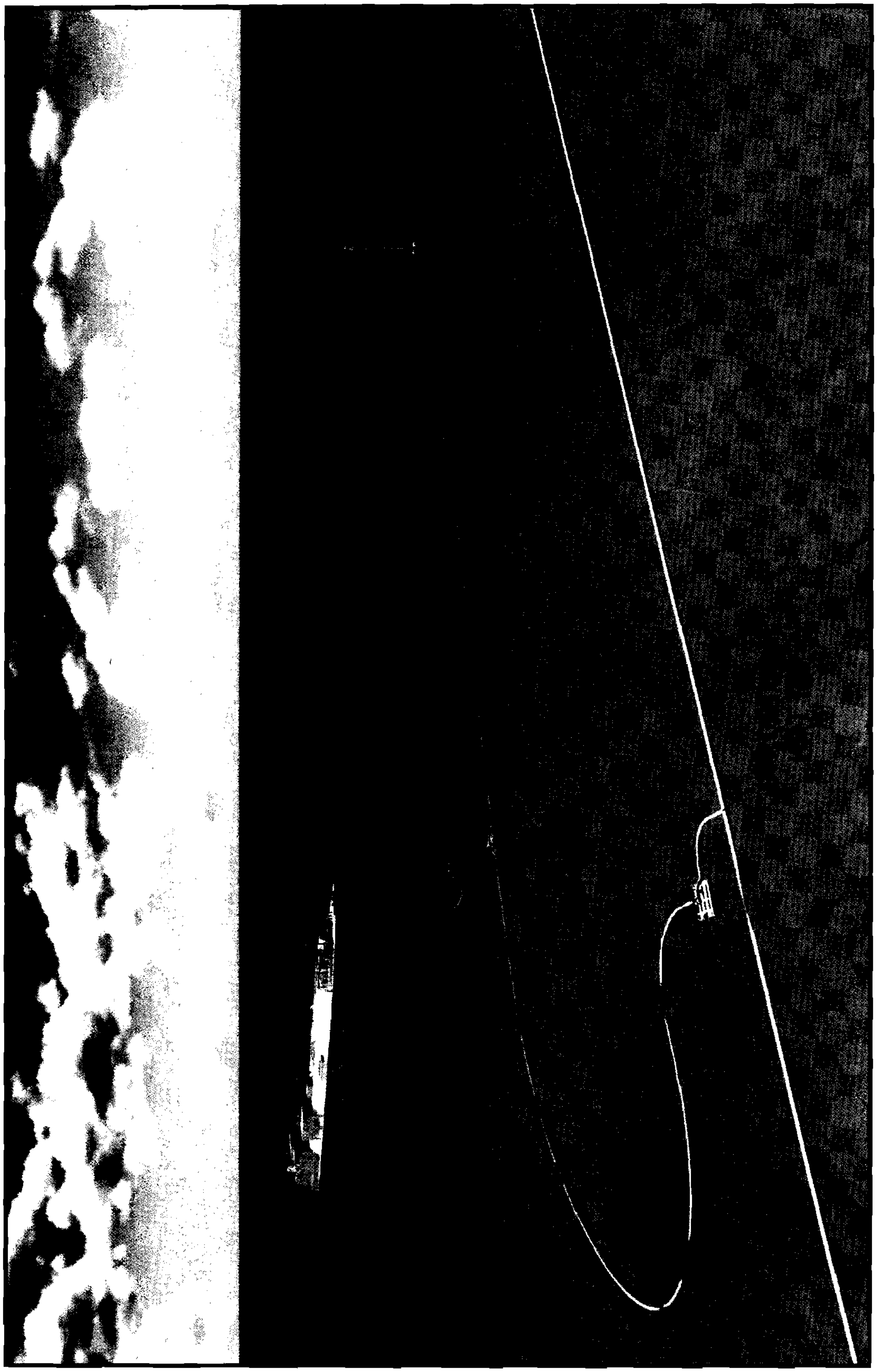


Figure 2.3-1. Neptune Project Location Diagram



Source: Neptune 2005f

Figure 2.3-2. Neptune Project Conceptual Site Plan unloading buoy to eight anchor points consisting of suction piles on the seabed. An SRV would typically moor at the deepwater port for between 4 and 8 days, depending on SRV size, vaporizer throughput, and sendout rate. The two separate buoys would allow natural gas to be delivered in a continuous flow, without interruption, by having a brief overlap between arriving and departing SRVs.

When not connected to an SRV, the unloading buoy would be submerged approximately 30.5 m (100 ft) below the sea surface and supported by means of buoyancy compartments. In this position, the buoy would be held on location by the mooring lines. A marker buoy and retrieval line would be used to locate and recover the buoy as an SRV arrives at the Port. The unloading buoy would be retrieved from its submerged position by means of a winch and recovery line. The unloading buoy would be hoisted into a trunk constructed in the forward part of the SRV where it would be located in a receiving cone. After the buoy is locked in position, unloading of natural gas would begin.

The SRVs would be equipped to store, transport, and vaporize LNG, and to odorize and meter natural gas that would then be sent out through conventional subsea pipelines. Each SRV would have insulated LNG storage tanks within its hull. Each tank would be equipped with an in-tank pump to circulate and transfer LNG, at a temperature of -160 °C (-256 °F), to the vaporization facilities on the deck of the SRV. The vaporization system would have a closed-loop, water-glycol cycle with re-circulating heat exchangers.

The Port would have an average throughput capacity of 500 MMscfd and a peak capacity of approximately 750 MMscfd. At the average throughput capacity, 50 SRV round trips per year would be required to supply the Port with LNG. Natural gas would be sent out by means of two flexible risers and a subsea flowline leading to a 24-inch gas transmission line (**Figure 2.3-2**). These risers and flowline would connect the Port to the existing 30-inch HubLine approximately 17.5 km (10.9 mi) west in Massachusetts Bay. From there, natural gas would be transported to serve residential, commercial, and industrial consumers, primarily in the northeastern United States.

LNG delivered to the Port would be obtained from the Applicant's affiliate companies' global portfolio of LNG supply at locations including the Caribbean, Africa, and the Middle East. The Applicant reported that it has obtained supply contracts for the capacity greater than the average vaporization rate for the project design life. Construction of the Port components would be expected to take 36 months including about 6 to 9 months of component installation at the proposed Port Site, with startup of commercial operations in late 2009. The Port would be designed, constructed, and operated in accordance with applicable codes and standards and would have an expected operating life of approximately 20 years.

The functions of the Port would be to temporarily moor SRVs, vaporize LNG, odorize and meter natural gas, and send out natural gas by pipeline. The major fixed components of the Port would be two unloading buoy systems in a water depth of approximately 76 m (250 ft); eight mooring lines consisting of wire rope and chain connecting each unloading buoy to anchor points on the seabed; eight suction pile anchor points; one flexible pipe riser to each buoy; riser manifolds; approximately 3.7 km (2.3 mi) of natural gas flowline connecting the two buoy systems; a single 24-inch natural gas transmission line (approximately 17.5 km [10.9 mi] long); and a transition manifold, hot tap, and connecting pipe tying into the existing 30-inch HubLine. These components are further described in subsequent subsections.

2.3.2 Lease Blocks and Overall Site Plan

The Port unloading buoys would be in MMS Lease Blocks NK 19-04 6525 and NK 19-04 6575. The lease blocks where the Port would be are shown in **Figure 2.3-3**. The SRVs would approach the Port

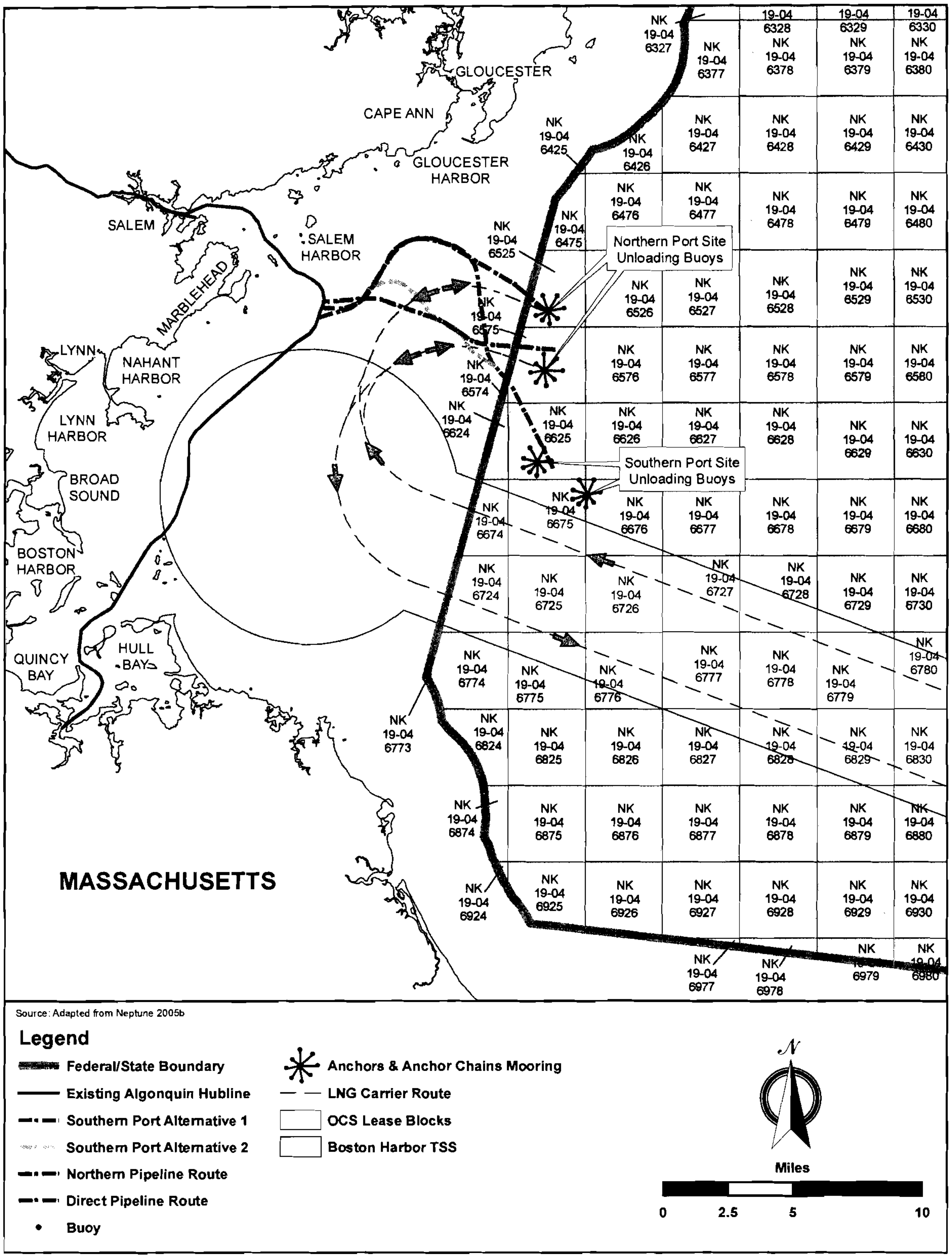


Figure 2.3-3. Lease Blocks in the Vicinity of the Neptune Project

in the Boston TSS, transit out of the TSS in state waters and re-enter the MMS lease block NK 19-04 as they approach or exit the Port. The flowline between the two unloading buoys and the natural gas transmission line would originate in and remain in block NK 19-04 6575 until the pipeline reaches the state/Federal boundary. **Table 2.3-1** lists the lease blocks identified as being within the project area and the SRV access and egress routes. There are no existing leases in any of the blocks identified in **Table 2.3-1**.

Figure 2.3-3 also shows the marine site plan for the Port. The site plan includes the proposed size and location of all fixed and floating structures and associated components seaward of the high-water mark. **Figure 2.3-3** also shows recommended ship routing measures and proposed vessel traffic patterns in the port area, along with proposed aids to navigation. The Port would have no associated anchorage areas for SRVs or support vessels.

Table 2.3-1. Lease Block Information

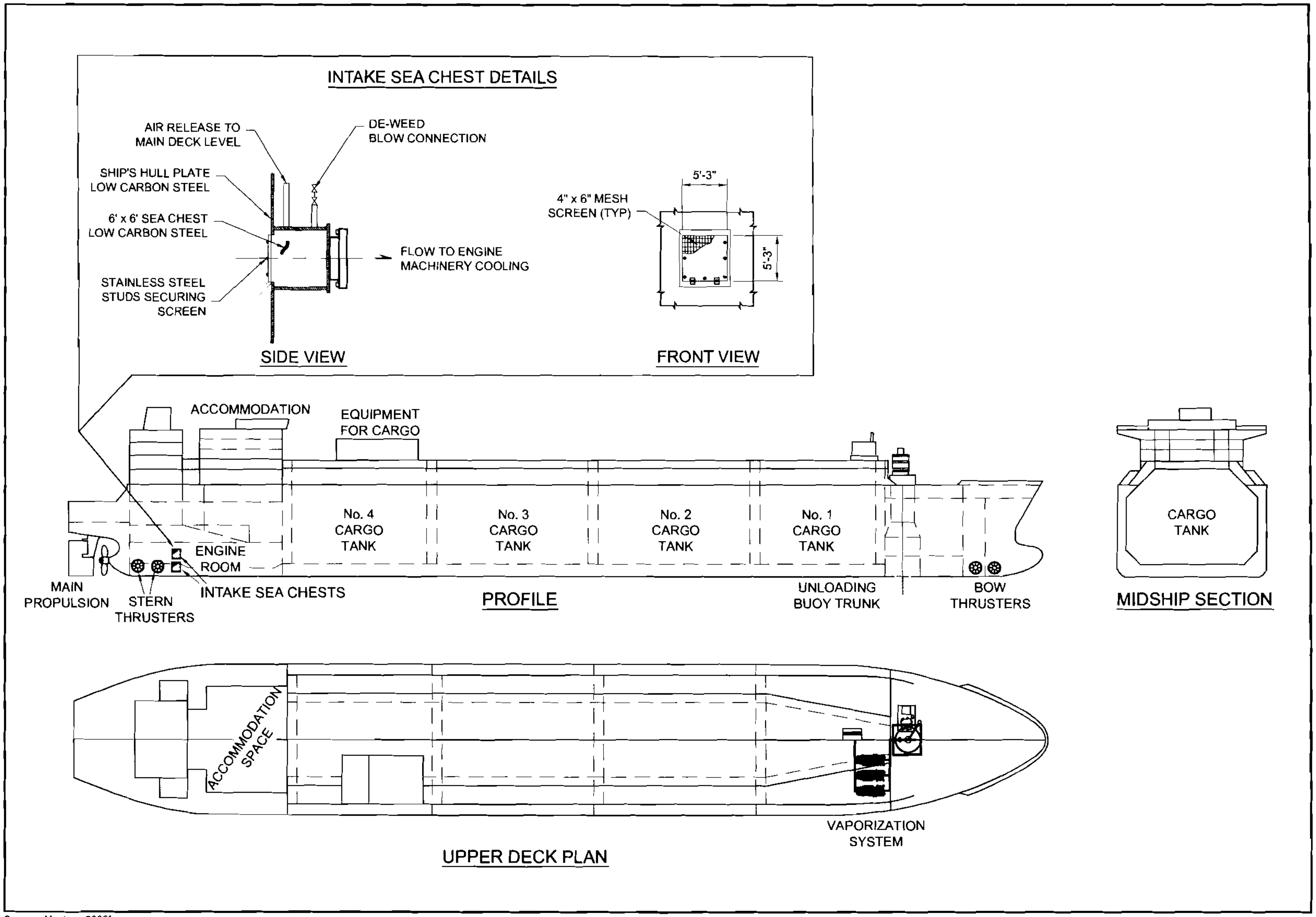
Description	OCS Area	OCS Lease Blocks
Northern Port Site		
North Unloading Buoy	NK 19-04 Boston	6525
South Unloading Buoy	NK 19-04 Boston	6575
Gas Transmission Line	NK 19-04 Boston	6575
SRV Route	NK 19-04 Boston	6525 and 6575
Southern Port Site		
North Unloading Buoy	NK 19-04 Boston	6625
South Unloading Buoy	NK 19-04 Boston	6675 and 6676
Gas Transmission Line	NK 19-04 Boston	6625 and 6675
SRV Route	NK 19-04 Boston	6625 and 6675

2.3.3 Shuttle Regasification Vessels

Three SRVs based on a standard design for oceangoing LNGCs would be used to supply LNG to the Project. The vessels would also be equipped with a trunk and mating cone to receive the unloading buoy, lifting and connection devices, an LNG vaporization system, and gas odorization and metering systems. The SRVs would have accommodations for as many as 42 persons. Normal crew size would be approximately 30 persons. All critical functions would be manned 24 hours per day; other functions would be accomplished on a regular, scheduled basis. The following provides details on each SRV.

Dimensions. Approximate dimensions of each SRV would be 280 m (918 ft) in length and 43 m (141 ft) breadth, with a design draft of 11.3 m (37 ft). The maximum height above the waterline would be 41.1 m (135 ft). A drawing of a typical SRV is shown in **Figure 2.3-4**.

Hull. The SRVs would have a flush deck without forecastle, a bulbous bow, and a transom stern. The engine room, crew accommodation, and bridge would be located aft. Two bow thrusters and two stern thrusters would be provided to improve maneuvering of the SRV when approaching the loading or unloading locations. A trunk and mating cone would be constructed in the forward part of the SRV to allow it to moor to the unloading buoy at the Port. The SRV would have a double hull arrangement. The inner hull would accommodate the membrane-type LNG storage tanks. The double bottoms and double sides would be used for seawater ballast. A conventional cargo manifold amidships would be provided for loading and unloading of the LNG at shoreside facilities.



Source: Neptune 2005f

Figure 2.3-4. Typical Shuttle and Regasification Vessel with Sea Chest Arrangement

Capacities. Each vessel's LNG storage tank total capacity would be approximately 140,000 m^3. The ballast tank capacity would be sufficient to limit the draft variations when loading and discharging the cargo. The SRV and the cargo containment and handling systems would be suitable for cargoes of specific gravities up to 0.50. Various tanks aboard each SRV would have approximately the following capacities: fuel oil tanks, 5,398 m^3 (1,426,000 gallons [gal]); diesel oil tanks, 238.5 m^3 (63,000 gal); distilled water tanks (two sets), 280.1 m^3 (74,000 gal); freshwater tanks (two sets), 250.0 m^3 (66,000 gal); and potable water tanks, 227.1 m^3 (60,000 gal). The fuel capacity would be sufficient for a range of approximately 13,000 NM with 5 days of reserve.

Propulsion and Electrical Power Generation. The SRV's power plant would use four dual fuel diesel engines, one producing 5.7 MW and three producing 11.4 MW. Two 11.4-MW engines would be used for electrical power generation when the SRV is moored. One 11.4-MW and one 5.7-MW engine would be needed for propulsion and electrical power generation when the SRV is underway. Propulsion would be provided by a single-screw driven by twin electric motors.

The dual-fuel diesel engines would burn 99 percent natural gas (a combination of 67 percent boil-off gas from the cargo tanks, 32 percent vaporized LNG), and 1 percent marine diesel as pilot fuel. The dual-fuel electric machinery concept would offer a significant improvement over traditional steam turbines in terms of operating economy, exhaust gas emissions, and redundancy. At the same time, standards of safety, reliability, and maintainability would be kept at appropriate levels. The increased economy over conventional steam plants is a result of the higher efficiency of dual-fuel engines. Instead of a conventional steam plant, the Project's SRVs would use two low-pressure marine auxiliary boilers, each rated at about 281 MMBtu per hour. These would be designed to operate on cargo boil-off gas and vaporized LNG. The steam would be supplied to the cargo vaporization units and not to the power generation and propulsion system.

Dynamic Positioning. The SRVs would have two tunnel thrusters forward and two tunnel thrusters aft. These thrusters push water out the side of the vessel to allow precise control of position while mooring with the buoy. Each thruster would have a controllable pitch propeller, with joystick control at the bridge house and bridge wings. The dynamic positioning system would be used while retrieving the submerged unloading buoy handling line and moving onto the buoy. The system normally would not be used while the SRV is moored to the unloading buoy. The SRV would be equipped with a thruster control system with a specially developed software program for handling all unloading buoy mooring operations. The SRV would also have a differential global positioning system (DGPS) and an acoustic position reporting system (APRS). The APRS would be used for monitoring the unloading buoy draft and its position before and during connection/disconnection. The bottom of the unloading buoy would be fitted with six transponders, equally spaced around the circumference of the lower part of the buoy. The APRS would automatically search for the strongest return signal from the buoy. If the APRS should lose the return signal from the transponder, the search procedure would start again.

SRV Mooring System. The SRVs would be equipped with normal mooring equipment for conventional LNGCs including port and starboard anchors. Head, breasting, and spring lines would be provided for mooring to shoreside LNG pier facilities. In addition, the SRVs that would be used at the Port would be equipped to moor to the unloading buoys.

LNG Containment System. The proposed cargo system would have four membrane-type tanks. The LNG with a specific gravity of typically between 0.43 and 0.47 would be stored at -160 °C (-256 °F). The maximum daily boil-off rate would be 0.15 percent of the cargo capacity. The final design chosen by the Applicant would comply with all IMO requirements applicable to vessels designed for a 40-year North Atlantic operational lifespan.

2.3.4 Vaporization and Process Facilities

Regasification System. Each SRV would be equipped with three vaporization units, each with the capacity to vaporize 250 MMscfd (about 210 metric tons per hour [MT/hr]). Under normal operation, two units would be in service, with a combined maximum sendout capacity of 500 MMscfd. The average annual sendout capacity would be expected to be 500 MMscfd. The third vaporization unit would be intended to be on standby mode, though an SRV would be designed for simultaneous operation of all units at a maximum sendout capacity of 750 MMscfd.

The vaporization system would be installed on the main deck in the front of the vessel. Each unit would be independent and could be disconnected from the main deck for transportation to shore for maintenance. Each unit would include the following components: one or two high-pressure cryogenic LNG pumps, one heating water-glycol circulation pump, one steam/water-glycol heat exchanger, one water-glycol/LNG heat exchanger, and one control module. LNG at -160 °C (-256 °F) and approximately 72 pounds per square inch (psi) would be pressurized in multistage centrifugal pumps to a pressure up to 1,740 psi. The LNG would then be evaporated and heated as gas ranging in temperature between 0 to 10 °C (32 to 50 °F). Heating would be accomplished in a shell-and-tube heat exchanger, where LNG would be evaporated and heated in the tubes, and water-glycol would flow through the shell and around the tubes that contain the LNG, heating the LNG in tubes.

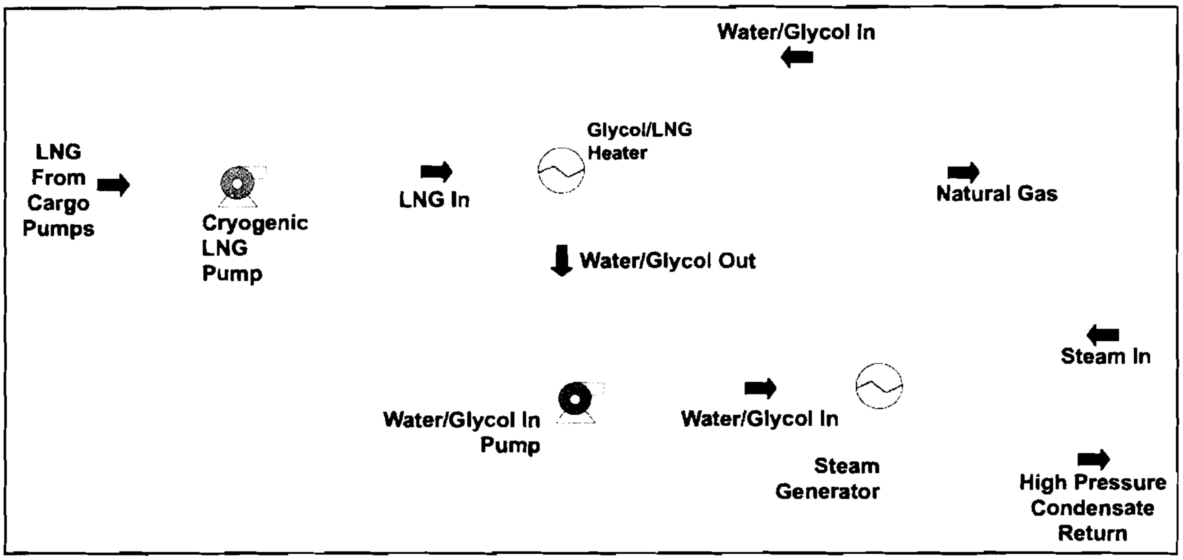
The intermediate media (water-glycol) used to heat the LNG would be warmed by steam generated in the auxiliary boiler. This avoids the use of steam from the SRV's boiler room directly in a heat exchanger against LNG. This would prevent the danger of hydrocarbon gas entering the boiler room if internal leakage in the LNG/steam heat exchanger were to occur.

The water-glycol would be circulated in a closed loop. Water-glycol, being pumped with sufficient head to drive it through the closed loop, would enter the LNG heat exchanger at 87.8 °C (190 °F) and leave at 20 °C (68 °F). The water-glycol would then be reheated in the steam/water-glycol heat exchanger to 87.8 °C (190 °F), at which time it would again enter the LNG heat exchanger.

The heating medium for the three vaporization units would be steam produced by the auxiliary boilers. Steam would be piped from the engine room to the steam/water-glycol heat exchanger. Condensed steam from the heat exchanger would be returned to the boiler feed water tanks at about 212 °F. Steam supply would be adjusted by a control valve regulated by the temperature of the vaporized LNG.

In addition to the three LNG vaporization units, a forcing vaporizer would be installed in the cargo compressor room to vaporize LNG, supplied by one of the spray pumps in the cargo tanks, for supplying fuel gas to the dual fuel engines. The capacity of the forcing vaporizer would be sufficient to produce the full quantity of fuel gas as forced boil-off to achieve 100 percent gas demand from the two dual fuel engines at maximum generated output. The closed-loop LNG vaporizer process flow diagram is presented in **Figure 2.3-5**.

Cooling and Ballast Seawater. Seawater would be used to ballast the SRV and cool the two dual-fuel diesel engines supplying power for the regasification process. Ballasting the SRV is required to maintain proper buoyancy as the LNG is vaporized and offloaded through the pipeline. Design of the cooling and ballast seawater system seeks to minimize amounts of seawater used. The seawater cooling and ballast system would take in seawater through two sea chests, each measuring 1.6 m by 1.6 m (5.25 ft by 5.25 ft). **Figure 2.3-4** shows the arrangement and cross sections of these sea chests. Over the vaporization cycle, an average intake of 360 m^3 per hour (2.25 MGD) would be required. The maximum



Source: Neptune 2005f

Figure 2.3-5. Closed-Loop LNG Vaporizer Process Flow Diagram

volume at any time during the vaporization cycle would be 1,100 m^3 per hour (1,575 gpm). Water velocity through the lattice screens at the hull side shell would not exceed 0.14 m/s (0.47 ft/s) at the maximum flow rate of 1,100 m^3 per hour (1,575 gpm). At the average intake of 360 m^3 per hour (2.25 MGD) the intake velocity would be 0.046 m/s (0.15 ft/s). This would result in an annual average use of 377 m^3 per hour (2.39 MGD) of seawater after allowing for the overlap periods when two SRVs would be moored.

Water supplied to the ballast tanks would be circulated through a seawater to freshwater heat exchanger to supply cooling to the two dual-fuel engines. The cooling water system has been designed to provide all necessary cooling from the water taken into ballast the SRV. Therefore, none of the cooling water would be discharged overboard at the Port. Discharges of ballast water would be made when the SRV took on its next cargo of LNG, and international and the local country's requirements for discharging ballast water would apply.

Produced Discharges. Because no process cooling water would be discharged, the SRVs would have only two production discharges while at the buoy, stack gases from the two auxiliary boilers and the two dual fuel engines, and discharges of stormwater from exposed deck areas.

Emissions would be produced by the two gas-fired marine auxiliary boilers, each rated at about 281 million British thermal units per hour (MMBtu/h), and from the two dual-fuel engines. The proposed boilers would have selective catalytic reduction (SCR) units to reduce NO_x emissions by about 85 percent to about 10 parts per million (ppm).

Two of the 11.4-MW dual-fuel engines would have SCR units to reduce NO_x emissions by about 92 percent at 50 percent engine load and 84 percent at 90 percent engine load. The SCR system would use urea as the catalyst agent to reduce NO_x formation. An oxidation catalyst would also be installed on the dual-fuel engines to reduce carbon monoxide (CO) and VOC emissions. One 11.4-MW dual-fuel engine and the 5.7-MW dual-fuel engine would not be provided with SCR as these engines would be used only for propulsion.

Boil-off gas would be fully consumed by the dual-fuel engines and boilers at an average annual send-out rate of 400 MMscfd. In the event of insufficient boil-off gas to fuel the engines and boilers at peak load, additional LNG would be vaporized and used. If excess boil-off gas were present, a thermal oxidizer would be used to burn the excess gas; the thermal oxidizer would only be operated when LNG vaporization equipment is shut down.

2.3.5 Operations

The following describes major aspects of Port operations.

Operations Manual. Based on available preliminary information, the Applicant has prepared a draft Operations Manual for the Port. As design and construction of the Port proceeds, the manual would be updated and resubmitted to the USCG for final approval prior to commencement of any operations.

Loading and Transit. LNG would be transferred from a foreign shoreside LNG pier to the SRVs. The loading operations would typically require approximately 1 day for berthing the SRV, loading the LNG, and preparing for departure from the LNG pier at the supply location. Normal security and safety policies would be followed and would comply with all applicable international rules and regulations. While in the open ocean, the SRVs would typically transport the LNG at speeds up to 19.5 knots and comply with the International Convention for the Prevention of Pollution from Ships (MARPOL), the Society of International Gas Tanker and Terminal Operators (SOLAS), and other applicable international rules.

Connecting, Vaporization, and Unloading. When an SRV is not moored to the unloading buoy, the buoy would be submerged approximately 30.5 m (100 ft) below the ocean surface, and the riser would remain attached. The valves at the top of the buoy and at the riser manifold would be closed. A pendant line would go from the top of the unloading buoy to a marker buoy that would be equipped with the required navigation lights. When the SRV approaches, the SRV would retrieve the unloading buoy with specific shipboard equipment, connect the buoy to the mating cone in the hull of the SRV, and prepare for vaporization and unloading of the LNG. Two unloading buoys approximately 3.7 km (2.3 mi) apart would be used so that natural gas could be delivered in a continuous flow without interruption by having brief overlap between arriving and departing SRVs. As the first SRV moored at the Port is emptied, a second SRV would arrive and moor at the Port.

Disconnection from Unloading Buoy. Prior to departure of the SRV, the unloading buoy would be disconnected and lowered to a neutrally buoyant location approximately 30.5 m (100 ft) below the ocean surface.

Manning and Crew Change. The SRVs would have accommodations for as many as 42 crew members, but the typical crew size would be approximately 30. All critical functions would be manned 24 hours per day. Other functions would be accomplished on a regular, scheduled basis. Crew changes would take place at the LNG loading site and not at the Port.

Pipeline Operation. The SRVs would control the normal pipeline system operations with onboard control and monitoring systems, unloading buoy valves, and the hydraulic control valve on the riser manifolds. A control umbilical containing electrical and hydraulic control circuits would allow remote control of buoy manifold and pipeline valves. Intervention and maintenance work might require divers or a remotely operated vehicle to open or close pipeline system valves. The pipeline system would be designed to accommodate subsea pigging operations, including passage of instrumented internal inspection devices. In addition, flanged connections and tie-in spools could be leak-tested underwater without having to pressure test the entire system. Pig launchers and receivers would be temporarily installed at two locations for pigging the flowline and the gas transmission pipeline.

2.3.6 Mooring and Unloading Buoys

The design of the mooring and unloading buoys would be based on proven technology used for more than a decade in hostile locations such as the North Sea, as well as in environmentally sensitive areas. The unloading buoy would have the same dimensions as other ports to provide the greatest flexibility for the quantity of vessels that could moor to the unloading buoy.

The size and length of the mooring lines, risers, and control umbilicals would be custom-designed for the site-specific conditions for the Port facility during the detailed design and construction phase of the Project. The mooring and unloading buoys would be designed for the SRV to remain moored on location during the 100-year storm conditions, and to survive the 100-year storm conditions when the unloading buoy is submerged below the ocean surface.

Unloading Buoys. The Port would include two unloading buoy systems in a water depth of approximately 76.2 m (250 ft) and separated by a distance of approximately 3.7 km (2.3 mi). Each unloading buoy would have eight mooring lines consisting of wire rope and chain connecting each unloading buoy to anchor points on the seabed, eight anchor points consisting of suction piles, one 16-inch inside diameter (ID) flexible pipe riser, and one electrohydraulic control umbilical from the unloading buoy to the riser manifold.

Buoyancy Cone. The buoyancy cone would be a welded, conical steel structure that would provide required buoyancy and ensure smooth transfer of mooring, riser/umbilical, and reaction forces to the vessel hull. The buoyancy cone would be locked into the mating cone in the SRV when the unloading buoy is connected. The outer shell would be designed to withstand expected impact loads during hook-up and disconnection, in addition to hydrostatic pressure in the submerged position. Physical contact with the vessel would be limited to the upper and lower mating rings, which require strict, interface tolerances. A vertical support structure would be located on top of the buoyancy cone. The top would also serve as a protective structure for the buoy-mounted valves and the male part of the mechanical connector so they would not suffer damage during connection and disconnection. Lifting and pull-in pad-eyes also would be integrated in the top of the structure.

Turret. The integrated turret would be the fixed portion of the unloading buoy. It would consist of a shaft and a lower section with mooring connections (pad-eyes). Mooring line tensions would be transferred into the turret through the turret pad-eyes. These forces would be further transferred via the bearings and into the buoy and vessel structure. The turret would be buoyant. To contribute to the overall buoyancy requirements, as well as to reduce thrust forces on the axial bearing during operation, it would be divided into separate watertight compartments. The turret would be equipped with integrated guide-tubes allowing the riser and umbilical to be pulled all the way through the turret for final suspension at the turret top plate.

Mooring Connection. Each mooring line would be connected to the lower turret section at a double lug integrated with the turret internal structure. A connecting link element would be fitted between the lugs and the mooring wire socket to allow free pivoting about both axes.

Turret Bearings. The main purpose of the turret bearings would be to ensure load transfer from the turret structure to the buoyancy cone and allow free and unrestricted rotation. There would be three main bearings in the buoy: upper axial bearing, upper radial bearing, and lower radial bearing. The upper axial bearing would support all the vertical loads from the mooring, riser/umbilical, and valve/connector/swivel assembly. This bearing would be exposed to the highest continuous loading. The turret bearings would be designed to allow full weathervaning of the vessel with no restrictions regarding weather conditions or vessel operation. All turret bearings would be made in segments of self-lubricating, sliding, bearing materials. The upper bearing segments (both axial and radial) would be fitted into a housing in the locking recess ring of the buoyancy cone. The lower bearing segments would be fitted into a housing in the lower ring of the buoyancy cone. The bearings could operate properly even when submerged in nearly stagnant seawater. The turret bearings would be designed to operate without additional lubrication.

Pick-Up Line System. To pull in the unloading buoy for mating to the SRVs, a pick-up assembly would be connected to the top of the unloading buoy. The main components would be a three-leg lifting bridle, a messenger line with spring buoys for attachment to the messenger line to obtain extra buoyancy, and marker buoys.

Anchors. Each unloading buoy would be connected to eight suction piles. Each pile would be 6 feet in diameter and approximately 20.1 m (66 ft) long. The anchor patterns for the northern and southern unloading buoys are shown in **Figure 2.3-2**.

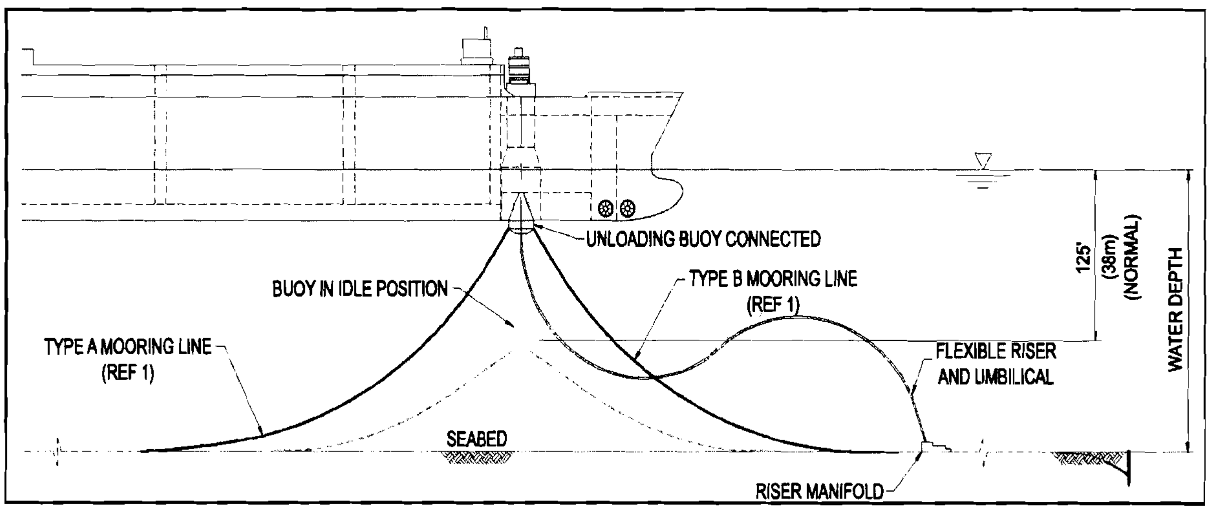
Mooring Lines. Each unloading buoy would have eight mooring lines designed so that the SRV could remain moored in the 100-year storm conditions. Mooring lines would vary in length, being from 548.6 to 1,219.2 m (1,800 to 4,000 ft) for the northern unloading buoy and from 762 to 1,097.3 m (2,500 to 3,600 ft) for the southern buoy. The mooring lines would consist of 5.25-inch Grade R4 chain and 5-inch spiral-strand wire rope. Information on the mooring lines is provided in **Table 2.3-2**.

Table 2.3-2. Mooring Lines

Anchor	Mooring Line Length (feet)	Heading from Buoy (degrees)	Water Depth (feet)
Northern 1	4,000	031.36	254
Northern 2	3,600	077.36	267
Northern 3	2,500	123.36	270
Northern 4	2,300	169.36	263
Northern 5	1,800	215.36	255
Northern 6	2,300	261.36	253
Northern 7	2,500	307.36	250
Northern 8	3,600	353.36	251
Southern 1	3,600	040.77	273
Southern 2	3,600	086.77	278
Southern 3	2,500	132.77	267
Southern 4	2,950	178.77	272
Southern 5	2,950	224.77	265
Southern 6	2,950	270.77	260
Southern 7	2,500	316.77	258
Southern 8	3,600	362.77	258

Flexible Risers. The riser system for each unloading buoy would consist of one 16-inch interior diameter flexible riser in a lazy-wave configuration (**Figure 2.3-6**). The riser would be directed between two of the mooring lines. A typical flexible riser has various layers consisting of the following, starting with the innermost layer:

- *Carcass.* Essentially a corrugated metallic tube that forms the body of the flexible pipe. The primary function is to prevent the polymer inner liner from collapsing due to possible external pressure or rapid decompression.
- *Pressure sheath.* An inner liner that is highly resistant to hydrolysis and virtually any chemicals used in the offshore industry.
- *Pressure armor.* Consists of C-shaped profiles.
- *Tensile armor.* Consists of two cross-wound layers of rectangular carbon steel wires providing the strength of the flexible riser with respect to axial forces that are induced by the internal working pressure, weight of the flexible pipe, and external loads (e.g., tension loads during installation or dynamic loads).
- *Insulation layer.* Applied before the extrusion of the outer sheath.
- *Outer sheath.* Protects the steel armor layers against mechanical damage and exposure to seawater, thus providing corrosion protection of the steel strands in both the pressure and the tensile armor.



Source: Neptune 2005f

Figure 2.3-6. Mooring System Configuration

End terminations and termination flanges would be at each end; end terminations would provide a gas relief system. In addition, the upper end would be fitted with a bend stiffener that would be pulled into the lower part of the J-tube in the unloading buoy.

Control Umbilicals. The control umbilical would connect the riser manifold controls to the control system onboard the SRV. The umbilical would have sufficient hydraulic lines to open and close valves and sufficient signal lines to transmit required information. The upper end of the umbilical would be fitted with a bend stiffener that would be pulled into the lower part of the I-tube in the unloading buoy.

The umbilical would be further fitted with an end termination and hang-off arrangement at the upper turret plate. The hydraulic and signal lines would be routed from the end termination to wet mateable connectors. At the manifold end, the umbilical would be fitted with an end termination that, most likely, would be bolted to the manifold. The hydraulic and signal lines would necessarily have wet mateable connectors. The umbilical would be fitted with distributed buoyancy and configured the same way as the flexible riser (either as stand-alone or strapped to the flexible riser).

Design Criteria for Mooring and Unloading Buoys. The maximum sea state for connection of the SRV to the unloading buoy would be a significant wave height of 3.5 m (11.5 ft), 1-hour mean wind speed of 30 knots, and current speed of 3.0 knots. The maximum sea state while connected to the unloading buoy would be a significant wave height of 11.0 m (36 ft), 1-hour mean wind speed of 68 knots, and current speed of 3.3 knots. The maximum sea state for disconnection of the SRV from the unloading buoy would be the 100-year condition of a significant wave height of 11.0 m (36 ft), wave spectral mean peak period of 14 seconds, 1-hour mean wind speed of 68 knots, and current speed of 3.3 knots.

2.3.7 Manifolds

Integral to the Project pipeline system would be two riser manifolds near the unloading buoys that would connect the flexible risers to the flowlines and a transition manifold and hot tap that would connect the new gas transmission pipeline to the existing HubLine.

Riser Manifolds. There would be two riser manifolds in the system, each within approximately 106.7 m to 109.7 m (350 ft to 360 ft) offset from the proposed unloading buoy locations. The purpose of the riser manifold would be to provide an interface between the pipeline system and the flexible riser, isolate the riser between gas unloading operations, and in the future attach a subsea pig launcher or receiver. Each riser manifold would include a flange connection for attaching the flexible riser or the subsea pig launcher/receiver and a full-bore subsea hydraulic control valve and electrohydraulic umbilical termination assembly (with allowance for remotely operated vehicle [ROV] and diver control). Each riser manifold would also include a full-bore subsea manual isolation valve (with allowance for ROV and diver control) and a small-diameter flushing and pressure-equalization spool. Each riser manifold would have a mud mat foundation to provide a stable base for bearing, as well as resisting, sliding, and overturning forces.

Transition Manifold and Hot Tap. The transition manifold would be part of an assembly that would include the hot tap to the existing HubLine. The assembly would consist of a manifold at the end of the gas transmission line, a hot tap at the HubLine, and a tie-in spool between the manifold and hot tap. The purpose of the transition manifold would be to provide an interface between the gas transmission line and the HubLine, to isolate the proposed gas transmission line when required, and to attach a future subsea pig launcher for the gas transmission line. The purpose of the hot tap assembly would be to provide access to the HubLine, as well as provide for isolation of the HubLine from the proposed gas transmission line when required.

The transition manifold and hot tap assembly would include two full-bore subsea manual isolation valves on the manifold (with allowance for ROV and diver control), two full-bore subsea manual isolation valves on the hot tap spool as a dual barrier system (with allowance for ROV and diver control), welded tees on the planned gas transmission pipeline (with a flange on the tee stub for attaching the tie-in spool), and a flange connection at the end of the gas transmission line for attaching a subsea pig launcher. There would also be a tie-in spool with a 90-degree elbow and misalignment flange at one end and a check valve and swivel ring flange on the other end, as well as a small-diameter flushing and pressure-equalization spool on the manifold. There would be a mud mat foundation to provide a stable base for bear and resist sliding and overturning forces.

2.3.8 Pipelines

The Project pipelines would consist of a 24-inch flowline approximately 3.7 km (2.3 mi) long from the southern riser manifold to the northern riser manifold. From the northern riser manifold a 24-inch gas transmission line approximately 17.5 km (10.9 mi) long would carry the gas from the unloading buoys to the existing 30-inch HubLine. The pipelines would have a nominal outer diameter of 24 inches, nominal wall thickness of 2.1 centimeters (cm) (0.812 inches), a fusion-bonded epoxy coating thickness of 0.041 cm (0.016 inches), and a concrete weight coating thickness of 7.6 cm (3 inches). The location and routing of the pipelines is shown in **Figure 2.3-4** and the basic pipeline design criteria are shown in **Table 2.3-3.**

Table 2.3-3. Pipeline Basic Design Criteria

Criteria	Value
Water depth range	100 feet to 300 feet
Maximum allowable operating pressure	1,740 psig
Normal operating pressure	1,000 psig
Throughput range	4 MMscfd – 75 MMscfd
Pipe fabrication method	Submerged arc welded
Steel unit weight	490 lbs per cubic foot
Concrete weight coating density	190 lbs per cubic foot
Design life	30 years

Note: psig – pounds per square inch gauge

Pipeline trenching and burial requirements are governed by 30 CFR 250 Subpart J, which requires pipelines and all related appurtenances to be protected by 1 m (3 ft) of cover in all portions in water depths less than 60.1 m (200 ft). Within state waters, portions of the pipelines in water depths greater than 60.1 m (200 ft) may also be buried to top of pipe. The flowline from the southern unloading buoy to the northern unloading buoy would be buried so that the top of the flowline is flush with the seabed. Trenching would protect the flowline from potential damage from anchors and trawls and avoid potential fouling, loss, or damage of fishermen's trawls. Concrete mats or grout bags might be used to protect the pipeline structures at tie-ins and manifolds. The transmission line from the northern riser manifold to the HubLine tie-in would be buried under at least 1 m (3 ft) of cover over the top of the pipe.

Marine Pipelines Metering System. The SRV's onboard control and safety systems would control pipeline pressures and flowrates at the discharge of the high-pressure LNG pumps. The Port's natural gas product would be metered for commercial purposes onboard the SRV. The metering system would be proposed on the forward part of the main deck between the vaporization units and the unloading buoy trunk. An ultrasonic gas metering system would consist of two ultrasonic gas flow meters, two pressure transmitters, and two temperature transmitters. A gas analyzer system would consist of a sample probe, two gas chromatographs, a pressure reduction cabinet, and an analyzer cabinet. The metering control system would consist of a metering cabinet, two flow computers, terminal flow computers and gas chromatographs, a supervisory computer and operator station, and a local area network switch.

Pipeline Crossings. The proposed gas transmission line route would cross one cable, the Hibernia Atlantic fiber optic cable which is in state waters in an approximate water depth of 45.7 m (150 ft). During construction, divers or ROVs would be used to locate and prepare the crossing, monitor the crossing during pipeline construction, and finalize the crossing after the pipeline has been installed, all in accordance with pre-approved and agreed-upon procedures. The gas transmission pipeline would be installed over the top of this cable in accordance with the requirements of 49 CFR 192.325, which mandates at least 30.5 cm (12 inches) of clearance from any other underground structure. It might be necessary to lower the existing cable to achieve the required clearance. Sandbags or concrete mats would be used to ensure 45.7 cm (18 inches) of separation between the proposed pipeline and the cable as mandated by 30 CFR 250.1003(a)(3). In the event that the installation results in less than 1 m (3 ft) of cover for portions of the new pipeline in water depths less than 60.1 m (200 ft) as mandated by 30 CFR 250.1003(a)(1), concrete mats would be used to provide an equivalent degree of protection.

2.3.9 Shipboard Piping, Controls, and Associated Equipment

Cargo System. The cargo system would include the necessary pumps and control systems for monitoring and control of the LNG storage tanks. The onboard class-approved load and stability calculator would ensure that liquids are properly distributed to minimize the stresses in the vessel hull. The operator would be able to monitor the cargo fluid levels, temperatures, and processes within each tank and control the valves for filling, emptying, and stripping the tanks. The operator could also monitor and control the auxiliary equipment associated with the cargo system, including the following:

- *Compressors.* One low-duty gas compressor used to provide boil-off gas for the boilers. Also, high-duty gas compressors, used to return LNG vapor ashore during loading operations, return gas/vapor ashore during gassing-up and initial cool-down operations, and circulate heated cargo vapor through the cargo tank system during warm-up operations.
- *Cargo discharge pumps.* Each LNG tank would be outfitted with two cargo discharge pumps. These pumps would be single-stage, centrifugal pumps with one inducer stage. The single stage would help to obtain a very low net positive suction head. The pumps would be of the submerged motor type, with the motor windings cooled by the pumped LNG. The LNG also would lubricate and cool the pump and motor bearings. The rated capacity would be approximately 5,600 gallons per minute.

Other Shipboard Systems. The SRVs would be equipped with all normal shipboard systems, such as a bilge and ballast system, safety equipment, lifesaving equipment, firefighting equipment, deck lighting, navigation aids, and all other equipment needed for compliance with the applicable codes, standards, and regulations. These would include the following:

- *Odorization system.* Provisions would be made to odorize the natural gas on board the SRVs. This would include provisions to connect injection equipment for the odorization agent (mercaptan) to the vaporized natural gas before it is offloaded form the SRV. The odorizing agent would be supplied in containers from shore. Provisions for safe storage of the containers would be arranged.
- *Cargo leak detection.* Any small cargo leakage within the membrane interbarrier space would be detected at an early stage by the gas detection system. The gas detection system would continuously monitor the interbarrier space by circulation of nitrogen within the space. Should a leak occur, it would be detected. Cargo would be restrained from coming into contact with the inner hull of the SRV by the secondary barrier membrane. An assessment of the leak could then be made and any special recovery measures such as emptying the tank concerned could be implemented.

- *Emergency Shutdown (ESD) System.* The ESD system would be designed to ensure a controlled shutdown of LNG equipment to avoid any unsafe conditions. It would be essential that the machinery be stopped and valves closed in the correct sequence to avoid any pressure or temperature surges that may exceed the design limitations of process or pipeline systems.
- *Accommodation and machinery spaces gas detection system.* This gas detection system would monitor the accommodation and machinery space areas of the ship. The range of measurement would be from 0 to 100 percent Lower Explosion Limit. The system would normally continuously scan the locations sequentially 24 hours per day, 7 days per week. In addition, a separate gas detector would be installed for continuous monitoring of gas supply to the main boilers.
- *Cargo areas gas detection system.* A separate gas detection system would cover the LNG insulation spaces and cargo area compartments. The control unit would be similar to the accommodation and machinery spaces gas detection system.
- *Fire detection and alarm system.* The fire detection system would be computerized with a fully addressable analogue fire alarm system and analogue detectors. The central control unit with back-up battery, operating panel, and power supply would be contained in a central cabinet on the bridge. There would be a repeater panel in the fire control headquarters. The system would be interfaced to the Distributed Control System which would indicate loop status and could control the fire pumps. The operator also would access deck plans indicating the exact location of individual detectors. The system would use a wide range of detectors and sensors to suit different needs and conditions. It would include detectors with different alarm parameters (for example, ion and optical smoke detectors, heat and flame detectors, manual call points, short circuit isolators, and timers where required). The detectors would be wired in a loop configuration with four loops in total. A fault in the system or a false alarm would be detected immediately because the function of the detectors and other installed loop units would be tested automatically and continuously.

2.3.10 Maritime, Safety, and Related Matters

The following identify several maritime, safety, and related matters pertaining to the Port.

Surface Requirements. Pursuant to the regulations of the DWPA, the USCG is authorized to establish a permanent mandatory Safety Zone around deepwater ports whether a vessel is present or not. The Safety Zone would extend approximately 800 m (2,624 ft) from the center of each Buoy and encompass approximately 994 acres. This is a result of maintaining 500 m from the moored LNGC (approximately 300 m length) as it weathervanes (rotates) around the buoy. All unauthorized vessels would be prohibited from anchoring or transiting the proposed Safety Zone at any time. The USCG would have the primary jurisdiction for the Safety Zone. In addition, there is an existing mandatory Safety and Security Zone that extends 3.2 km (2 mi) ahead and 1.6 km (1 mi) astern, and 457 m (1,500 ft) on each side of any LNGC while underway within Captain of the Port (COTP) Boston zone.[14]

If a License is issued, the USCG may designate a mandatory No Anchoring Area (NAA) and recommendatory ATBA to further facilitate Port operations, safety, and security. These restrictions would be implemented in place of the Applicant's proposed Precautionary Area that includes an approximate 1,200-m (3,937-ft) radius around each of the buoys. While the USCG would assess a number of safety and security considerations to designate a boundary of the final NAA and ATBA, the radius proposed by the Applicant will be used as a baseline to assess potential impacts. The NAA is

[14] 33 CFR 165.110

necessary to prevent vessels from anchoring (or bottom trawling) within the Port's mooring system and damaging the mooring system, the vessel itself, or its equipment. The ATBA would represent an advisory notice to mariners to seek alternate routes around the area if possible. The USCG would not prevent vessels from crossing the ATBA, but they would be expected to maintain a predictable course at a speed of 10 knots or less. Activities that would not threaten port operations or navigational safety, such as fishing and transiting through the ATBA by recreational boaters or whale watching vessels, would be allowed within the ATBA. The Applicant would be encouraged to develop communications protocols with parties who have an interest in transiting the Project area such as fishing, whale watching, or recreational boating.

If the License is approved, the USCG, in working with the applicants, could determine that additional operational restrictions such as a Precautionary Area are required. NAAs, ATBAs, and other restrictions need to be proposed to and approved by the IMO if they extend beyond the 19-km (12-mi) limit. The Applicant would be encouraged to develop communications protocols with parties who have an interest in transiting the Project area such as fishing, whale watching, or recreational boating. A notice of any operational restrictions or area designations would also be placed in the *Federal Register*.

Mooring Line Break Detection. Monitoring of possible mooring line failure would be based on the change in mean turret offset position. If the mean turret offset position from the latest 30 minutes deviates more than 1.98 m (6.5 ft) from the previous 30 minutes mean turret offset position, then there would be a potential line breakage in one of the windward lines. Both averages would be updated for each DGPS reading and displayed on a monitor. A line failure alarm could either be given automatically or based on visual monitoring of the two mean offsets. In case of visual monitoring, this should be performed approximately every 30 minutes. The system would be designed for single line failure, and therefore disconnection would not be necessary immediately upon detection of a potential line failure.

Navigational Lighting. While attached to the unloading buoy, the SRV would be considered "a vessel at anchor." Accordingly, it would exhibit the light and sound signals appropriate to a vessel at anchor in accordance with International Regulations for Prevention of Collisions at Sea (COLREGS). Thus, the SRVs at anchor would exhibit one all-round white light in the fore part and one all-round white light at or near the stern and at a lower level than the light in the fore part. The SRV would also use the available working or equivalent lights to illuminate her decks. To minimize impacts on marine animals, all lighting would be installed and used in accordance with the USFWS guidelines described in **Section 4.2.1.10.**

The messenger retrieval line for the submerged buoy, which would float on the surface of the water when an SRV is not connected, would be provided with two lighted buoy markers. The lighted buoy markers would be used to assist during retrieval of the buoy by the SRV and to alert vessel traffic of the presence of the floating messenger line when an SRV is not on station. The lighted buoy markers would be fitted with flashing yellow lights.

Pollution Prevention Equipment. There would be no ship-to-ship fuel oil transfer operations at the Port, minimizing the possibility of fuel spill. Coamings (approximately 7.6 to 10.2 cm [3 to 4 inches] high) would be built around hydraulic deck machinery (winches and cranes) and associated piping on deck to contain potential leakage. While moored at the Port, the deck would be patrolled by the crew around the clock. In addition, all deck areas would be continuously monitored by closed-circuit television cameras from the cargo control room and the bridge. In this way, the vessel would be able to respond immediately if any leak should occur. Oil spill recovery equipment would be deployed adjacent to possible sources for hydraulic oil spills. Such equipment would include sawdust, shovels, and portable pumps (connected for immediate use). Any spilled oil (contained in coamings) would be pumped into storage drums and retained on board for transportation to a shore disposal or recycling facility. In addition to these measures, the Neptune Port would operate under the provisions of an approved oil spill contingency plan.

Waste Treatment Equipment. Each SRV would be equipped with an approved sewage treatment unit sized to suit the SRV quarters' capacity. While at the Port, discharge from the sewage treatment unit and other accommodation drains would be collected in a tank for later disposal at sea, away from the Port and in accordance with international regulations. Bilge drains in engine and machinery spaces would be directed to an oily bilge holding tank. An emulsion-breaking oily water separator in compliance with the latest rules and regulations would be fitted. While at the Port, the bilge would be retained in bilge holding tanks. During sea voyage, the oily bilge separator would reduce the oil content to less than 15 ppm. The separated oil would be stored in holding tanks for disposal ashore at the LNG loading location or sent to the shipboard incinerator. The incinerator would be used to dispose of contaminated fuel waste cleaning materials, oil, and any oil recovered from the machinery space bilge separating system. All trash from the accommodations, including plastic, would be compacted and returned to shore for proper disposal.

Fuel Bunkering of SRVs. No vessels would be used for bunkering of fuel or LNG into SRVs that use the Port.

Shore-based Support. A support vessel would be used for monitoring and control purposes and occasional supply and personnel transfer. It would be expected that this vessel would be an ocean class towing vessel up to approximately 44.2 m (145 ft) long, 12.2-m (40-ft) beam, and 6.7-m (22-ft) draft, powered by up to two diesel engines with up to 7,000 horsepower. The vessel would be equipped with firefighting equipment. It would be able to rescue tow an SRV in up to Beaufort 5 conditions and perform security functions. The support vessel would operate from an existing dock facility in Boston or Gloucester. The deepwater port would receive commercial, logistics, legal, operations, and administrative support from existing offices in Boston, Massachusetts, that are presently occupied by an affiliate of the Applicant, Tractebel LNG North America LLC.

2.3.11 Construction and Installation

Construction of the components for the Port would occur at seaside or upland areas, and installation would occur at the ocean site. This work would comply with relevant environmental, pipeline, maritime, and coastal regulations governing the construction process. The following provides details on these matters.

Fabrication, Storage, and Handling. The first step in construction would be ordering pipe and other material and preparing fabrication contracts based on final design and specifications for major components of the deepwater port. Fabrication contractors for major components would be selected through an international solicitation process. Major components would include

- *SRVs.* The SRVs would be built at an international shipyard that has extensive and recent experience in the design and construction of SRVs. The shipyard selected would have the capability to construct and install the vaporization facilities and the mating cone for the unloading buoy.
- *Mooring System and Unloading Buoys.* The major components would be custom-fabricated, based on the final engineering design and specifications, at worldwide manufacturing facilities that have expertise and experience in manufacturing offshore mooring systems and buoys.

The manufactured components would be shipped to the region, and stored temporarily at an existing onshore staging yard (typically at or near the dock of a nearby port, such as Boston or Gloucester). Quality assurance and inspections would be conducted either at the site of manufacture or the storage and handling yard to ensure the components meet engineering design specifications. These components would include anchor piles, mooring lines, concrete-coated flowline and gas transmission pipeline, manifolds and spool pieces, unloading buoys, and flexible pipe risers.

Offshore Construction Sequence. It is anticipated that the offshore installation effort would be accomplished in the following sequence:

- Mobilize an anchored lay barge for the Northern Pipeline Route, dynamic positioning derrick for the Direct Pipeline Route, and pipelaying vessel and workboats.
- Install the anchor piles and the lower portion of the mooring lines.
- Install the two riser manifolds and the transition manifold.
- Install the flowline between the riser manifolds.
- Install the new gas transmission pipeline from the northern riser manifold to the transition manifold and the hot tap to the HubLine.
- Conduct pipeline hydrostatic testing.
- Connect the mooring lines to the unloading buoys and properly tension the mooring lines.
- Connect the two risers and control umbilicals between the unloading buoys and the riser manifolds.
- Demobilize the offshore construction equipment.

Description of Offshore Construction Equipment. An anchored lay barge would be used to install the flowline, gas transmission pipeline, and manifolds[15]. Pre-lay and post-lay surveys of the pipelines could be performed from the lay barge but can be accomplished with a smaller vessel. An oceangoing tug or supply vessel would regularly supply the construction barges with construction consumables, equipment, food, and other supplies; and take away any trash or equipment to be returned to shore.

All construction vessels would likely come from the Gulf of Mexico. The derrick/lay barge, anchor-handling vessels, and diver support vessel (DSV) would each make 2 trips (1 roundtrip) to transit in and out of the area, and would stay on station (i.e., at the offshore construction sites) for the majority of the construction period. The supply vessel and crew/survey vessel would make regular trips between the construction sites and the ports of Boston or Gloucester. During Project installation, the supply vessel would make approximately 102 trips (51 roundtrips) and the crew/survey vessel would make approximately 720 trips (360 roundtrips), for a combined total of 822 trips (411 roundtrips). The overall total of vessel trips associated with all construction vessels would be approximately 830 trips (415 round trips).

[15] The Applicant has expressed a preference to use a dynamic positioning derrick lay barge for installation of pipelines. In the event this type of vessel is not available due to high demand primarily in deepwater Gulf of Mexico, an anchored lay barge would be used. Analysis in the EIS/EIR assumes use of an anchored lay barge, operational use of which would impose more impacts due to the continual repositioning of its anchor system.

Preconstruction Activities. The following activities would be accomplished prior to start of offshore construction operations:

- Hazard surveys
- Development and approval of detailed construction procedures
- Pre-lay survey of pipeline routes
- Placement of protective mats over any pipelines or cables to be crossed by the flowline and the planned gas transmission pipeline
- Placement of marker buoys and transponders on the seafloor (if required).

Equipment Mobilization. The pipe lay and derrick barge vessel, a diving support vessel, and a pipe burial plow would be mobilized to the operating site and load any remaining project supplies from the project mobilization port. Approved construction procedures would be delivered to each construction vessel and a kick-off meeting to review construction procedures, health and safety procedures, and environmental limitations would be held with key personnel prior to starting each construction activity.

Offshore Construction Plan. The following identify the planned construction procedures.

- *Mobilization to the Operating Site.* Materials, including unloading buoys, mooring lines, risers, and control umbilicals, would be transported from the shore-based storage area to the operating site by a deck cargo barge or anchor-handling vessel. Cargo barges would transport the concrete-coated line pipe and manifolds to the operating site.
- *Anchor Installation.* The prefabricated anchor piles would be installed offshore with a dynamic positioning derrick barge, anchor-handling vessel, or similar offshore construction equipment. The anchor points would be within a radius of 487.7 to 1,097.3 m (1,600 to 3,600 ft) of the center of each unloading buoy. This operation would take approximately 5 days.
- *Flowline and Manifolds.* A pipelaying vessel would install the two riser manifolds, install the flowline between the riser manifolds, and complete the hydrostatic testing and dewatering of the flowline. The flowline would be 24-inch-diameter line pipe with concrete weight coating, and have a length of approximately 3.7 km (2.3 mi). The flowline would be buried by a towed plow, even in water depths of more than 60.1 m (200 ft). Trenching would begin approximately 91.4 m (300 ft) from the southern riser manifold and end approximately 91.4 m (300 ft) from the northern manifold to avoid damaging such structures. Transition sections would use suction pumps, jetting machines, airlifts, or submersible pumps as required. A post-trenching survey would be performed to verify that the proper depth is achieved. Subsequent trenching runs might be performed to further lower sections that do not meet burial depth requirements. This operation would take approximately 16 days.
- *Gas Transmission Pipeline to the HubLine.* The transmission pipe (with concrete weight coating) would be transported from the temporary shore base to the operating site. The transmission line construction sequence would begin with plowing of the pipeline trench. A pipelaying vessel would install the 24-inch-diameter pipeline from the northern riser manifold to the location of the transition manifold near the connection point to the HubLine. A site for the transition manifold would be dredged adjacent to the HubLine, and then the manifold would be laid in place. The tie-in to the HubLine would be completed, and hydrostatic testing and dewatering of the pipeline from the northern riser manifold to the HubLine would be performed. The gas transmission line would be buried from the transition manifold to the

northern riser manifold. Trenching would begin approximately 91.4 m (300 ft) from the northern riser manifold and end approximately 91.4 m (300 ft) from the transition manifold to avoid damaging such structures. Transition sections would use suction pumps, jetting machines, airlifts, or submersible pumps as required. A post-trenching survey would be performed to verify that the proper depth is achieved. Subsequent trenching runs might be performed to further lower sections that do not meet burial depth requirements. This operation would take approximately 22 days.

- *Unloading Buoys.* The unloading buoys would be offloaded in the vicinity of the designated site. An anchor-handling vessel or small derrick barge would connect the mooring lines from the anchor points to each unloading buoy, and then adjust the mooring line tensions to desired levels.
- *Risers.* The anchor-handling vessel or small derrick barge would also connect the riser and the control umbilical between each unloading buoy and the associated riser manifold, complete the hydrostatic testing and dewatering of the risers, and test the control umbilicals.
- *Pipeline Hot Tap Installation.* The hot tap fitting, which would not require welding, would provide full structural reinforcement where the hole would be cut in the HubLine. The tapping tool and actual hot tap procedure would be supplied and supervised by a specialist from the manufacturer. Prior to construction of the hot tap, divers would excavate the HubLine tie-in location using suction pumps. The concrete weight coating would be removed from the HubLine and inspected for suitability of the hot tap. The hinged hot tap fitting would then be lowered and opened to fit over the 30-inch HubLine. The hot tap fitting then would be closed around the pipeline, the clamp studs and packing flanges would be tightened, and the fitting leak would be tested. The HubLine then would be tapped and the valves would be closed. The hot tap and exposed sections of the HubLine would be protected with concrete mats until the tie-in to the transition manifold occurred.
- *Demobilization.* Upon completion of the offshore construction effort, side scan sonar would be used to check the area. Divers would remove construction debris from the ocean floor. All construction equipment would leave the site.

Pipeline Hydrotests. There would be one combined gas transmission line and flowline hydrotest (the whole system would be in-line and piggable) including flooding, cleaning, and gauging following pipelay, trenching, and burial. The pig-launcher would be sized to launch a minimum of one flooding pig, one brush/cleaning pig, one gauge pig, and one dewatering pig. Additional pigs could be required following detailed design. The gas transmission line and flowline would require approximately 3.0 million gallons of filtered seawater, including complete flushing of the system and 676 gallons of fluorescent dye TADCO Tracer Fluro Yellow XL500-50 Liquid Dye, or an approved equivalent. This volume assumes that no water would bypass the pigs and would include approximately 1,700 gallons of water in front of the flooding pig and approximately 1,700 gallons of water between other pigs (reduced from two hydrotests to one hydrotest). The Applicant has assumed that flooding would take place from the southern riser manifold to the HubLine hot tap manifold.

Dewatering pigs, driven by nitrogen, would dewater the gas transmission line, flowline tie-in spools, and manifolds from the southern riser manifold temporary pig launcher to the HubLine end temporary pig receiver. All hydrotest water discharges would be in Federal waters, near the unloading buoys. The total pipeline system would be swab-dried using a pig train with slugs of glycol or similar fluid. The water content of successive slugs would be sampled to verify that the total pipeline has been properly dried. The Applicant has assumed the hydrotesting and dewatering operation would take approximately 1 week if glycol were used for drying the total pipeline system; the operation would take considerably longer if vacuum drying were to be used.

Functional Testing. During the construction of the SRVs and fabrication of the unloading buoy components, mating checks would occur to confirm the SRV is properly moored to the unloading buoy and that all piping has been pressure-tested in accordance with appropriate standards and requirements. Upon completion of offshore construction and availability of an SRV, the SRV would perform a trial connection to each unloading buoy and would verify the functionality of all components prior to initiating any discharge operations. The purpose of the functional testing would be to verify that all components are compatible and will function as designed, prior to the vaporization of LNG and sendout of natural gas. Particular attention would be given to the following:

- Confirmation of the operation of the unloading buoy acoustic position reporting system
- Onsite verification of the SRV thrusters and the dynamic positioning system
- Verification of the unloading buoy retrieval into the mating cone of the SRV and the mechanical connection between the SRV and the unloading buoy
- Verification of mooring line tensions in comparison with the predicted values
- Function test and verification of the gas tight connection between shipboard equipment and the unloading buoy turret
- Confirmation of the emergency shutdown and the emergency buoy disconnect systems
- Verification of SRV disconnect from the unloading buoy.

Construction Schedule. Construction of the deepwater port components is expected to take 36 months. Onsite construction activities in Massachusetts Bay would be initiated in mid-May 2009 and completed by mid-September 2009. The final task would be inspection of all construction areas and removal of any construction debris. Start-up of commercial operations is expected in late 2009.

Construction Contingency Plan. This section describes contingency plans in the event that any problems are encountered during the construction period. The Applicant has prepared a contingency schedule using the same individual operations as the base case construction schedule. The base case schedule is shown in **Figure 2.1-5**, and the contingency schedule is shown in **Figure 2.1-6**. The contingency schedule includes additional lines showing allowances for combinations of weather downtime, mechanical downtime, or any other contingencies including unforeseen circumstances that could cause delays to the Project.

- *Equipment Mobilization Contingencies.* The derrick/lay vessel, the dive support vessel, and the pipe-trenching unit would be mobilized to the operating site (probably from the Gulf of Mexico) and load any remaining project supplies from the project mobilization port. The provisional work period of mid-May to mid-November 2009 conflicts with the typical Gulf of Mexico work season. There might be more vessel availability if there were more timing flexibility; flexibility would be limited due to various local restrictions during the planned summer construction period. Dynamically positioned lay vessels could also potentially be mobilized from Canadian Atlantic ports or from North Sea ports.
- *Schedule Contingencies.* The proposed installation schedule shows items installed in a certain order. While some items must be installed before others, there remains some flexibility in the order (e.g., anchors and mooring lines, the hot tap, and the manifolds can be installed before or after the gas transmission line and flowline) and the natural gas transmission line and flowline can be installed from east to west or from west to east. The principal concern would be delays in pipeline trenching due to inability to plow to full depth. Geotechnical surveys indicate that soft-bottom substrates along the Northern Route would not

present problems. If difficulties are encountered, the Applicant has identified schedule contingencies to allow completing pipeline installation without exceeding the proposed construction window.

- *Weather/Mechanical Downtime.* There could be delays caused by weather downtime, or mechanical downtime, which would be covered under the construction contract. During the installation vessel and contractor selection period, due consideration would be given to selecting construction vessels that would minimize delays due to weather. Construction planning would include identification of hazards and specific mitigation plans, including identifying and preparing equipment and components to be on call on the vessels or locally ashore should they be needed. The Applicant has proposed a Summer Construction Schedule to minimize potential weather-related delays. In addition, the Applicant proposes to select construction vessels (to the maximum extent possible) that could operate in a broad range of weather conditions.

If proposed construction methods prove to be ineffective, the Applicant has evaluated several alternatives to mitigate the impacts. For pipeline installation, contingencies include using anchored barges to increase force on the plows, following the first vessel with a second plow a short distance behind to achieve full depth, plowing to maximum achievable depth and installing concrete mats over areas that did not attain full depth, or jetting some portions of the pipeline route.

Other construction activities, such as riser and manifold installation, anchor and cable installation, and shoring the interconnection excavations to speed installation, have been identified that could be employed to regain the schedule if significant schedule impacts were encountered.

2.3.12 Decommissioning

The Port would be designed to have a service life of 20 years. At the end of that period, the principal elements of the Port would be decommissioned.

Shuttle and Regasification Vessel. The SRV would be decommissioned by transporting it to a suitable facility for removal of LNG equipment that would be used on other LNGCs or shoreside facilities, or for salvage. The ship would likely be converted to another type of use. At the end of its useful life as a seagoing vessel, it would likely be salvaged for recycling of metal and other materials.

Unloading Buoy. At the end of the economic life of the Port, the subsea valves would be closed, the risers and control umbilicals would be disconnected from the riser manifolds, and the mooring lines would be disconnected from the unloading buoys and from the anchor points. Such major components would be removed from the Project area.

Pipeline System. The pipelines would be decommissioned in place. The owner of the pipelines would submit a pipeline decommissioning application to the MMS Regional Supervisor in accordance with 30 CFR §250.1750 through §250.1754. The Minerals Management service (MMS) Regional Supervisor would determine whether the pipelines would constitute a hazard obstruction to navigation and commercial fishing operations, would unduly interfere with other uses of the OCS, or would have adverse environmental effects. Decommissioning would include the following:

- Closing hot tap valves and plugging the end
- Pigging and flushing the pipelines
- Filling the pipelines with seawater

- Removing the manifolds and tie-in spools
- Cutting and plugging each end of the pipelines
- Burying each end of the pipelines under at least 1 m (3 ft) of cover or covering each end with protective concrete mats, if required by the MMS Regional Supervisor.

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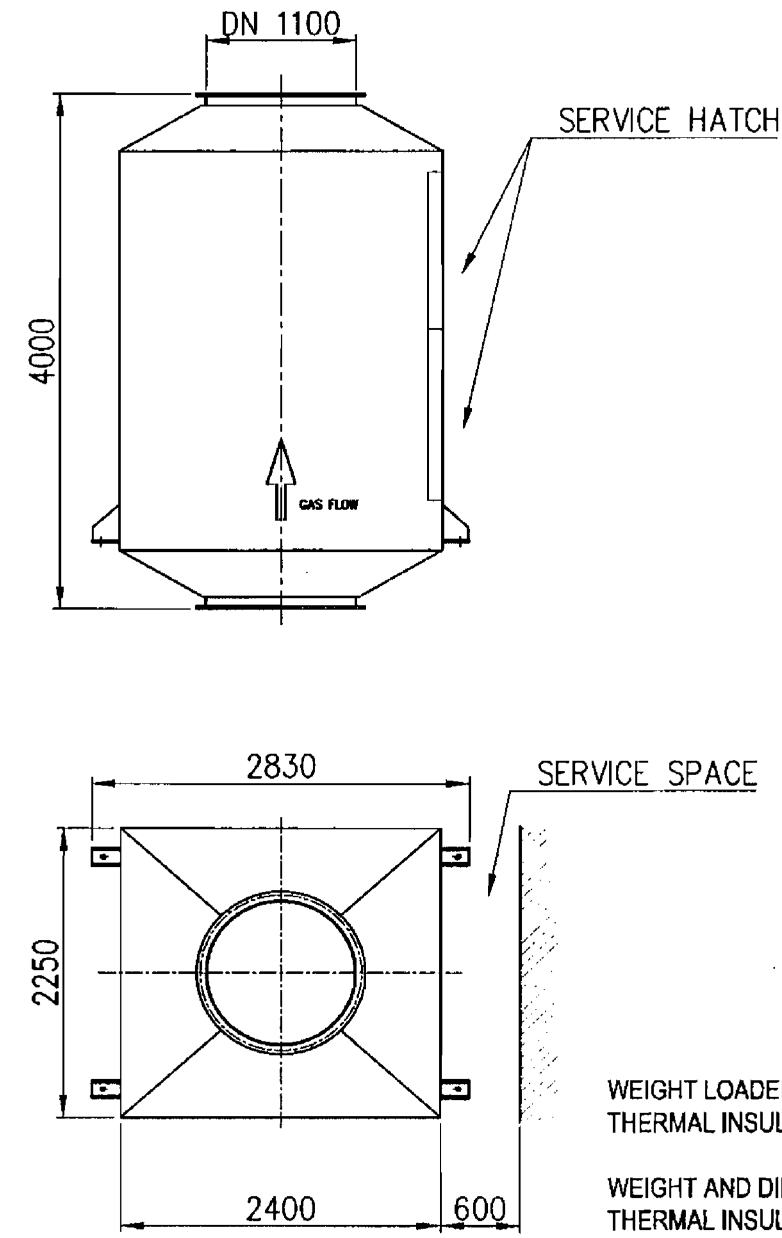


WEIGHT LOADED 6.1 TONNES
THERMAL INSULATION 100 MM

WEIGHT AND DIMENSIONS INCLUDES
THERMAL INSULATION AND CATALYST

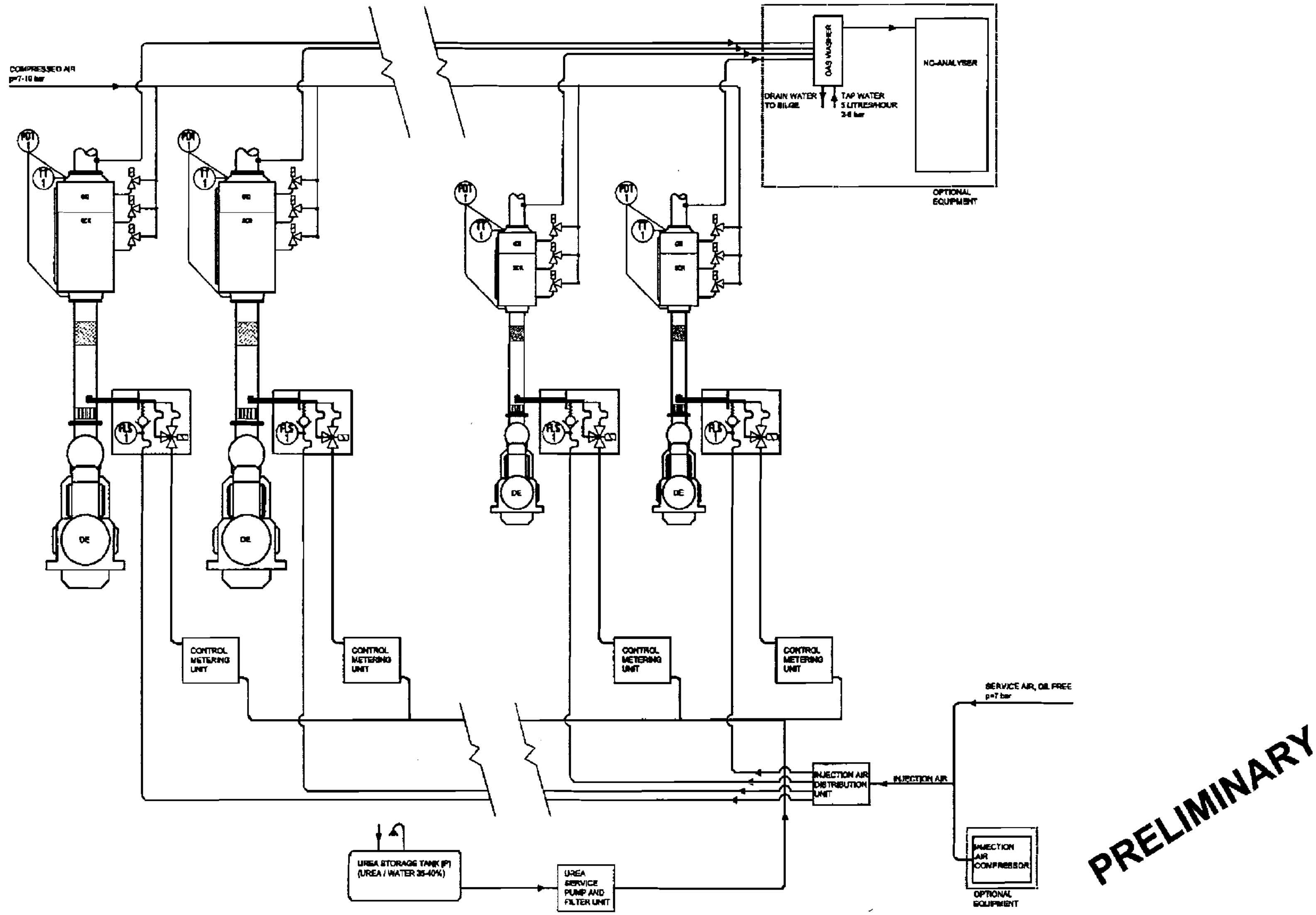
PRELIMINARY

Drawn	Constr.	Scale		Date	Project	Sket	Filename
CA	CA	1:50	A4	05-05-12			182V-2.dwg

Munters
DIESEL EMISSION CONTROL

SCR CONVERTER SYSTEM
CONVERTER TYPE 182V

Replace	
Revision	Revision date
DRAWING	182V-2



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MOL	MOL	- A3	03-01-14			

Munters
DIESEL EMISSION CONTROL

SCR CONVERTER SYSTEM
SCR PRINCIPAL ARRANGEMENT
MULTIPLE DIESEL ENGINES

Replace:
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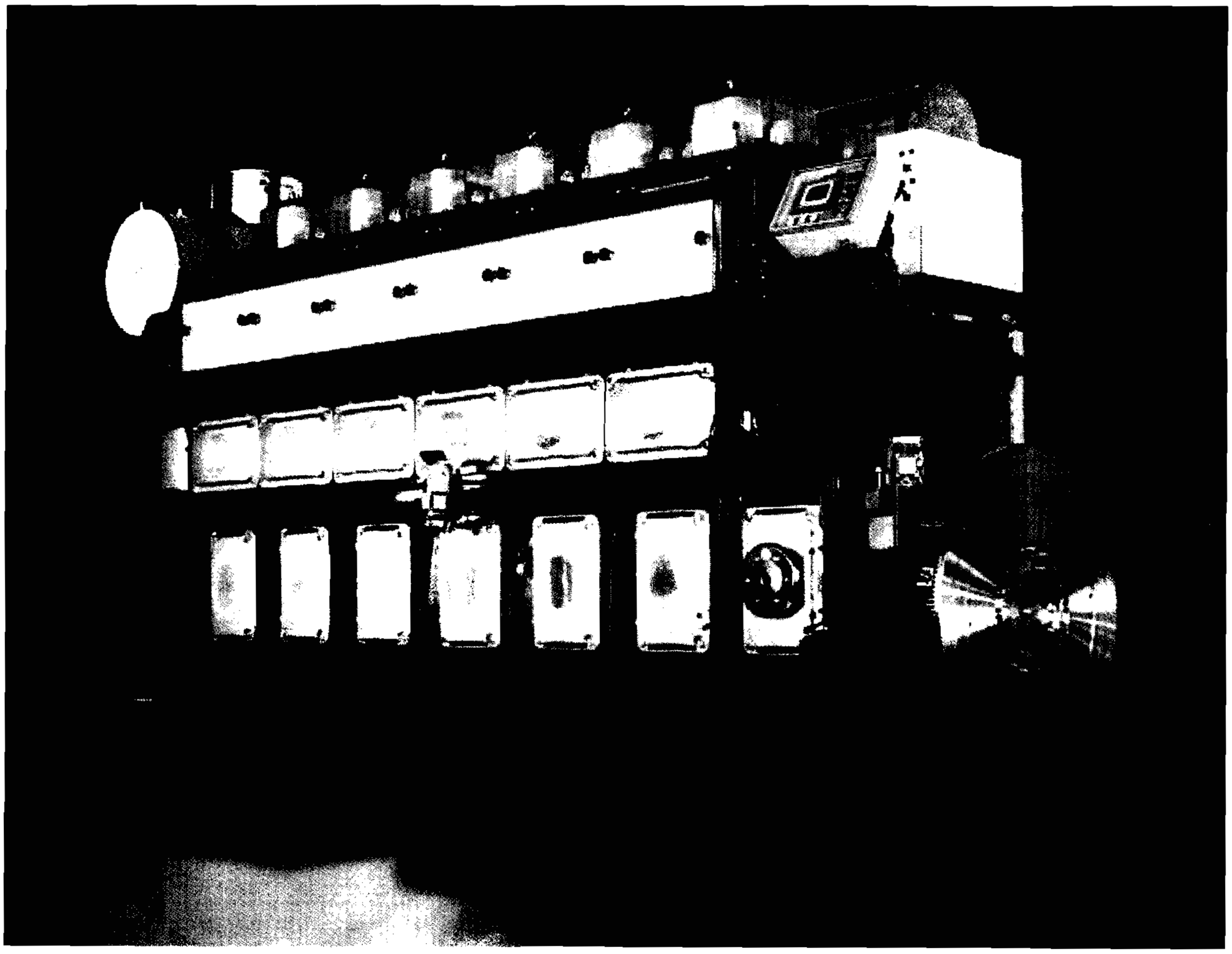


Wärtsilä 50DF

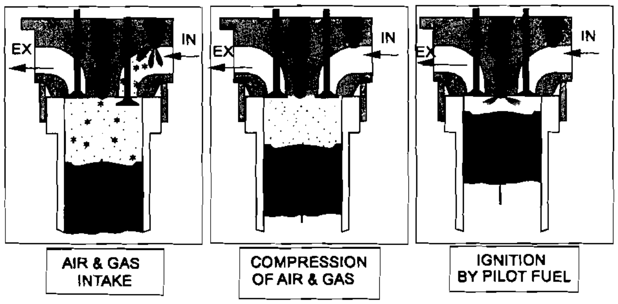
Design

The WÄRTSILÄ® 50DF is a four-stroke dual-fuel engine. The engine can alternatively run on natural gas, marine diesel fuel (MDF) and heavy fuel oil (HFO). The Wärtsilä 50DF is designed to give the same output regardless of whether it is running on natural gas or on liquid fuel. The engine operates according to the lean-burn principle: the mixture of air and gas in the cylinder is lean, which means that there is more air than needed for complete combustion. Lean combustion increases engine efficiency by raising the compression ratio and reducing peak temperatures, and therefore also reducing NO_X emissions. A higher output is reached while avoiding knocking or preignition of gas in the cylinders.

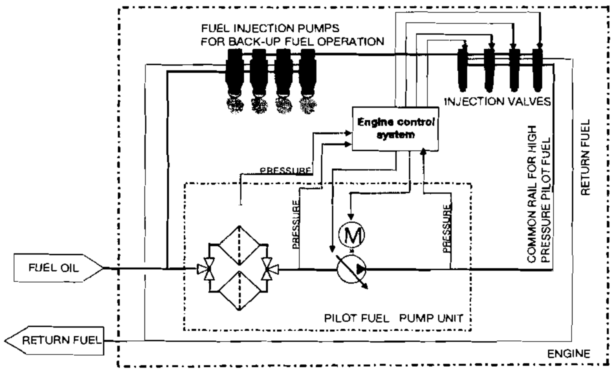
Combustion of the lean air-fuel mixture is initiated by injecting a small amount of MDF (pilot fuel) into the cylinder. The pilot fuel is ignited in a conventional diesel process, providing a high-efficiency ignition source for the main charge.

The fuel oil system on the engine has been divided into two: one for pilot fuel oil and one for the main fuel oil for back-up fuel operation. The equipment used for fuel oil operation is similar to the conventional diesel engine, with camshaft-driven injection pumps at each cylinder. The engine is equipped with a twin-needle injection valve, one main needle used during diesel mode and one for pilot fuel

WÄRTSILÄ



oil. The pilot fuel is elevated to the required pressure by one common pump unit, including filters, pressure regulator and an engine-driven radial piston-type pump. The pilot fuel is distributed through common-rail type piping and injected at approximately 900 bar pressure into cylinders. Pilot fuel injection timing and duration are electronically controlled.



Engine fuel oil system, MDF operation.

When running the engine in gas mode, the pilot fuel amounts to less than 1% of full-load consumption.

The fuel gas system feeding the engine with fuel includes a gas valve unit. This unit includes a pressure regulating valve, gas filter, instrumentation, and the necessary shut-off and venting valves to ensure safe and trouble-free gas supply. The fuel gas feed pressure to the engine is controlled by the pressure regulating valve located on the gas valve unit. The fuel gas pressure is dependent on engine load and the fuel gas calorific value (lower heating value). On full engine load, the required gas pressure to the gas valve unit is about 5 bar(g), depending on gas LHV. On the engine, the electronically actuated and controlled gas admission valves give exactly the correct amount of gas to each cylinder. This enables reliable performance without shutdowns, knocking or misfiring.

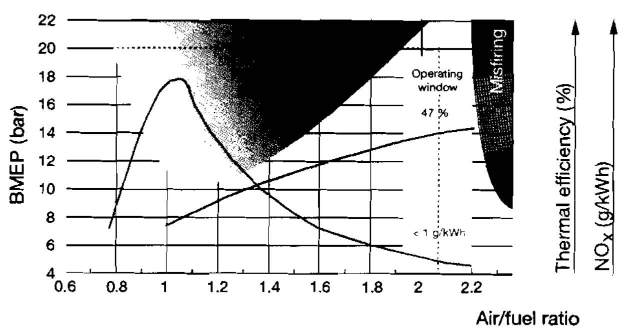
Operation

The Wärtsilä 50DF engine is designed for generating electrical power for ship propulsion. The dual-fuel engine operates on natural gas as main fuel, and on diesel as backup fuel. The Wärtsilä 50DF engine can be switched from gas operation to backup fuel operation at any load. The switchover is instant and the engine has the capability to operate on backup fuel if needed, without interrupting power generation. Fuel oil is always circulating through the engine, ensuring sufficient fuel supply for pilot fuel and for quick switchover to backup fuel operation. The engine can be switched from backup fuel operation to gas operation at loads up to 80% of full load.

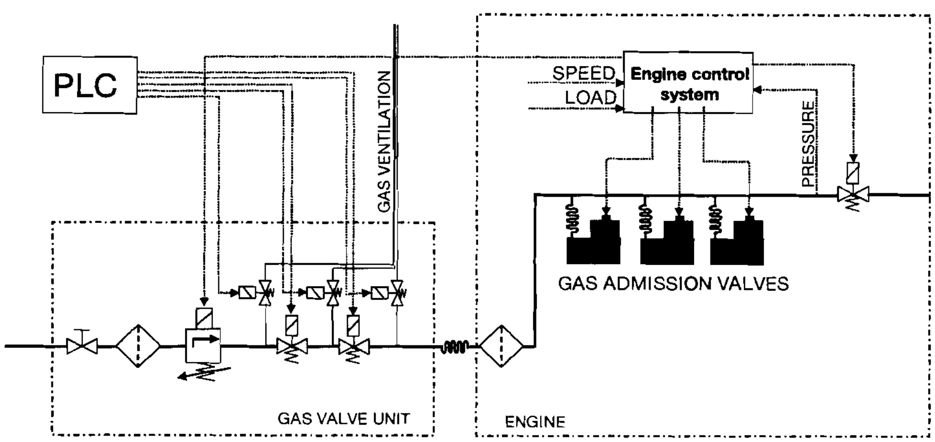
The engine is also capable of running on heavy fuel oil (HFO). The engine can be operated as a conventional diesel engine when running on HFO.

Emissions

In the Wärtsilä 50DF engine, the air-fuel ratio is very high. Since the same specific heat quantity released by combustion



Optimized engine performance.



Fuel gas system.

is used to heat up a larger mass of air, the maximum temperature and consequently NO_X formation are lower.

The engine has a thermal efficiency of 47%, higher than for any other gas engine. This, and the clean fuel used, give engine extremely low CO_2 emissions.

Typical emissions:		
Engine in gas operating mode		
Typical emission levels*	100% load	75% load
NO_x (g/kWh)	1.4	2
CO_2 (g/kWh)	430	450
Engine in diesel operating mode		
Typical emission levels*	100% load	75% load
NO_x (g/kWh)	11.5	12
CO_2 (g/kWh)	630	630

* note that the emission level always depends on the gas composition and that these figures should be seen as indicative only.

Automation

The engine is controlled by a sophisticated engine control system, a fully integrated engine management system designed for harsh environments. It ensures maximum engine performance and safety by monitoring and controlling vital engine functions. The engine control system is a modularized system consisting of hardware modules. The modules communicate through buses based on CAN protocol. The control system monitors temperatures and pressures on the engine through the numerous sensors mounted on the engine.

The engine control system offers the following advantages:

- Easy maintenance and high reliability thanks to rugged engine-dedicated connectors and pre-fabricated cable harness
- Easy interfacing with external systems via a databus
- Reduced cabling on and around the engine
- High flexibility and easy customizing
- Digital signals - free from electromagnetic disturbance
- Built-in diagnostics

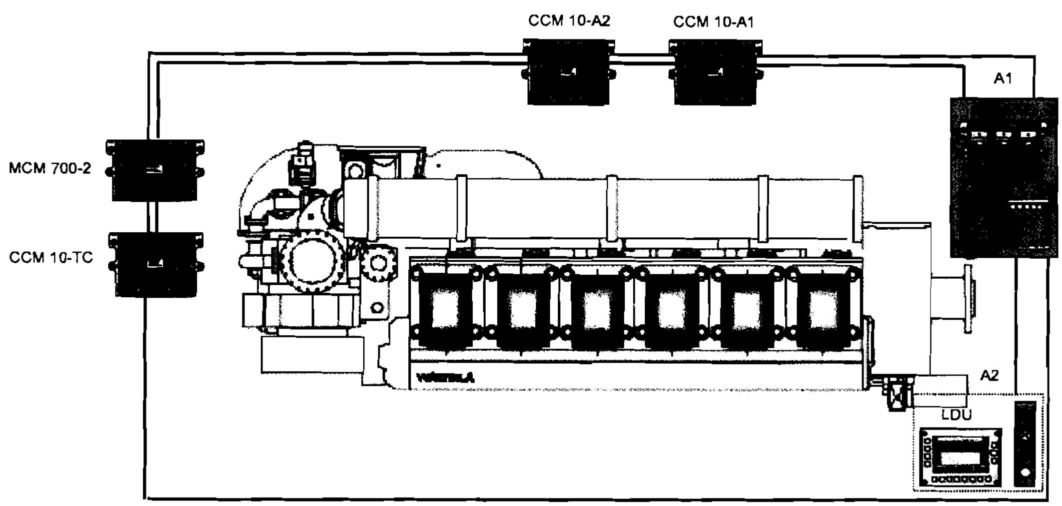
Maintenance / service intervals

Thanks to the purity of gas, Wärtsilä 50DF offers long component lifetime and time between overhauls. The engine has a large opening into the crankcase and camshaft to facilitate checking and maintenance.

References

The dual-fuel engine operates on well-known technology. The Wärtsilä 50DF is closely related to the smaller Wärtsilä 32DF engine, and uses the same techniques and operating principles. Wärtsilä DF engines with over 450,000 accumulated running hours are operating worldwide in marine offshore installations and also in land-based power plants.

Installation/deliv.	Country	Engine type	Output
Atlantique M32 -03	France	4x6L50DF	22.8 MW
Atlantique N32 -04	France	1x6L+3x12V50DF	39.9 MW
Bermeo -04	Spain	1x6L50DF	5.7 MW
Manisa -04	Turkey	3x18V50DF	51.3 MW
Atlantique P32 -05	France	1x6L+3x12V50DF	39.9 MW
HHI 1777 -06	Korea	2x9L+2x12V50DF	39.9 MW
HHI 1778 -07	Korea	2x9L+2x12V50DF	39.9 MW
HHI 1779 -07	Korea	2x9L+2x12V50DF	39.9 MW
HSHI 297 -07	Korea	2x9L+2x12V50DF	39.9 MW
Total		32 engines	319.2 MW



Engine control modules.

Safety aspects

The Wärtsilä 50DF engine is designed for safe operation. The engine is always started on liquid fuel using both main diesel injection and pilot fuel injection. Gas admission is activated only when combustion is stable in all cylinders and all engine parameters are normal.

Before the engine can operate on gas, the fuel gas feed system has to perform a series of tests to ensure the function together with safe and reliable operation. The test procedure is done automatically and this way the engine can be operated safely in both gas and diesel operating mode. Automatic and instant trip to back-up fuel operation is initiated in the case of certain alarm situations.

The engine room is regarded as a safe area free from gas. The gas feed system has venting valves that safely relieve pressure from gas piping when the engine switches over from gas operation. The venting pipes are routed to a safe area away from the engine room. Gas piping on the engine can be of either single wall or double wall type. At double wall gas piping installations, the intermediate space is ventilated by air.

Most major classification societies have prepared or are in a process of preparing new rules for modern low-pressure, dual-fuel engines.

Fuel gas specifications

Property	Unit	Value
Lower heating value (LHV), min [1]	MJ/m³N [2]	28
Methane number (MN), min [3]		80
Methane (CH_4), min	% volume	70
Hydrogen sulphide (H_2S), max	% volume	0.05
Hydrogen (H_2), max [4]	% volume	3
Ammonia, max	mg/m³N	25
Chlorine + fluorines	mg/m³N	50
Particles or solids at engine inlet, max	mg/m³N	50
Particles or solids at engine inlet, max size	μm	5
Gas inlet temperature	°C	0...50

Water and hydrocarbon condensates at engine inlet not allowed [5]

1) The required gas feed pressure depends on the LHV.

2) Values given in m³N are at 0 °C and 101.3 kPa.

3) The methane number (MN) is a calculated value that gives a scale for evaluation of the resistance to knock of gaseous fuels.

4) A hydrogen content higher than 3% volume must be considered separately for each project.

5) The dew point of natural gas is below the minimum operating temperature and pressure.

Main data

Cylinder bore . . . . 500 mm
Piston stroke. . . . . 580 mm
Cylinder output . . . . 950 kW/cyl
Engine speed . . . . 500, 514 rpm
Mean effective pressure . . . . 23.6, 23.0 bar
Piston speed. . . . . 9.7, 9.9 m/s
Fuel specification:
Fuel oil. . . . . Marine diesel oil
ISO 8217, category ISO-F-DMX, DMA and DMB,
heavy fuel oil 730 cSt/50°C ISO-F-RMK 55
Natural gas. Methane Number: 80
LHV: min. 28 MJ/nm³
Fuel consumption:
Gas operation: Total BSEC: . . . . 7410 kJ/kWh
Backup fuel operation: SFOC: . . . . 189 g/kWh
With engine driven pumps, 5% tolerance. ISO 3046 standard ambient conditions. Fuel oil LHV 42.7 MJ/kg

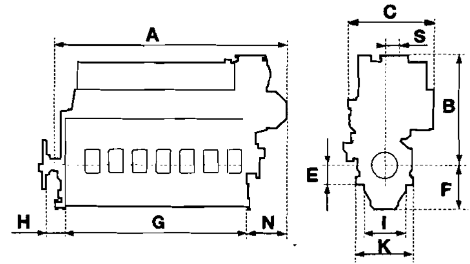
Rated power: Generating sets

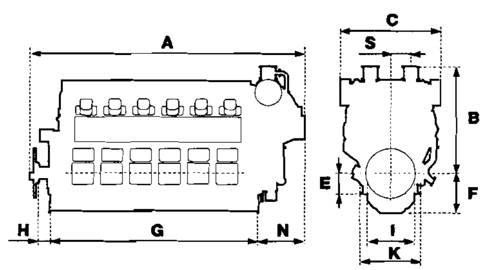
Engine type	500 rpm/50 Hz, 514 rpm/60 Hz	
	Engine kW	Gen. kW
6L50DF	5 700	5 500
8L50DF	7 600	7 330
9L50DF	8 550	8 250
12V50DF	11 400	11 000
16V50DF	15 200	14 670
18V50DF	17 100	16 500

Principal engine dimensions (mm) and weights (tonnes)

Engine type	A	B	C	E	F	G
6L50DF	8 115	3 580	2 850	650	1 455	6 170
8L50DF	9 950	3 600	3 100	650	1 455	7 810
9L50DF	10 800	3 600	3 100	650	1 455	8 630
12V50DF	10 465	4 055	3 810	800	1 500	7 850
16V50DF	12 665	4 055	4 530	800	1 500	10 050
18V50DF	13 725	4 280	4 530	800	1 500	11 150
	H	I	K	N	S	Weight*
6L50DF	460	1 445	1 940	1 295	395	96
8L50DF	460	1 445	1 940	1 620	315	128
9L50DF	460	1 445	1 940	1 620	315	148
12V50DF	460	1 800	2 290	1 840	765	175
16V50DF	460	1 800	2 290	1 840	815	220
18V50DF	460	1 800	2 290	1 785	815	240

* Weights are dry weights (in Metric tons) of rigidly mounted engines without flywheel. All dimensions in mm.





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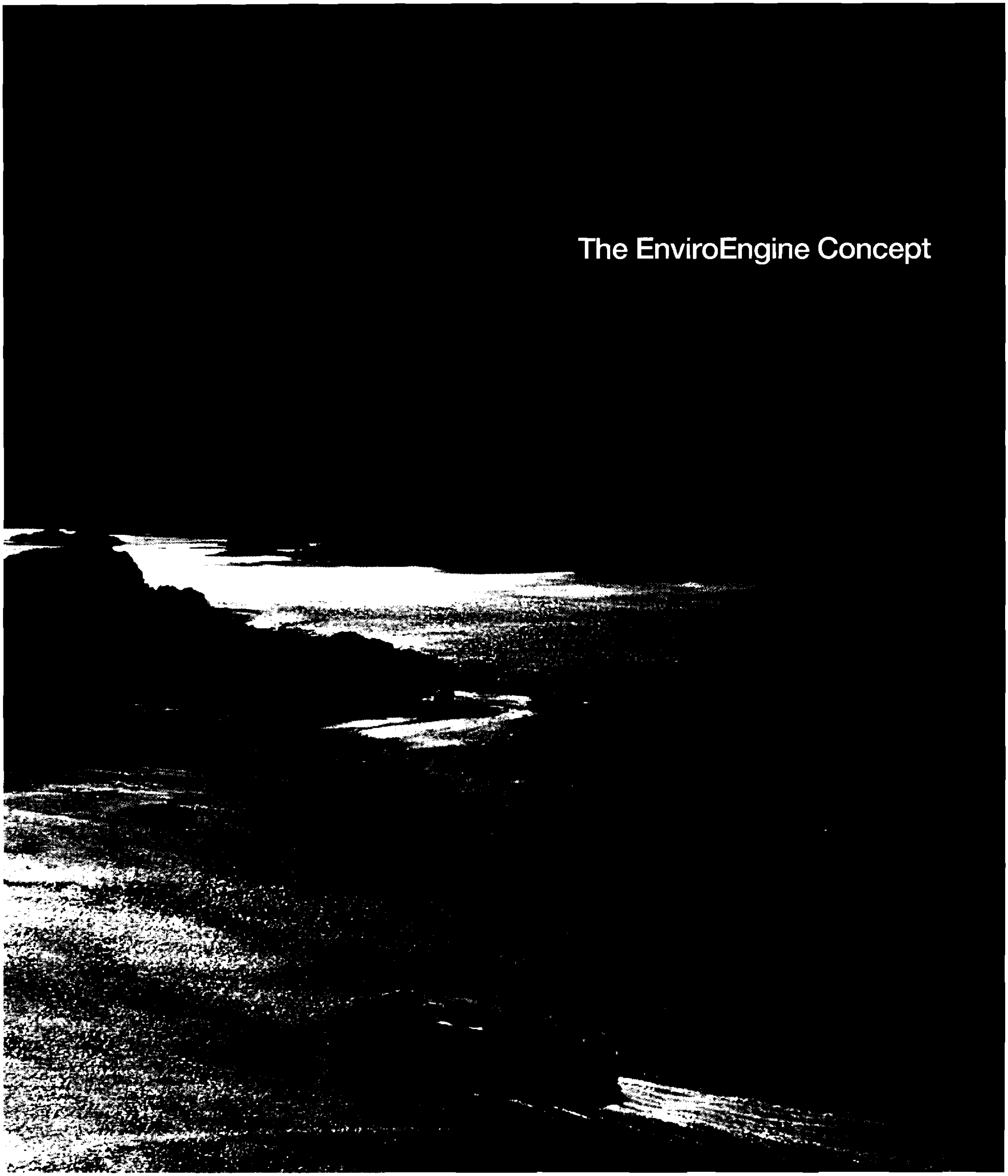
The EnviroEngine Concept



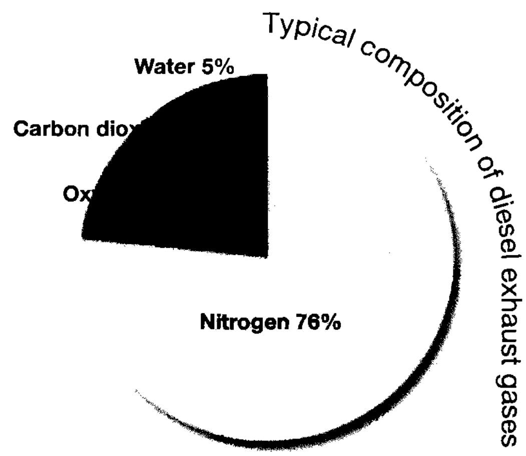
WÄRTSILÄ

The EnviroEngine Concept

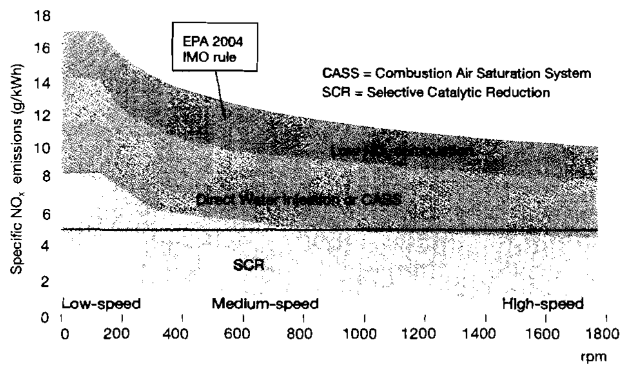
To meet the increasing pressure to make ships more environmentally friendly Wärtsilä is committed to keeping well ahead of international environment regulations and legislation.

Wärtsilä's aim is to provide shipowners with the most environmentally sound prime movers without compromising overall operational economy. All experience and research effort have been gathered in the EnviroEngine concept. EnviroEngines combine several innovative Wärtsilä technologies such as Common Rail Fuel Injection, Direct Water Injection and Selective Catalytic Reduction.

The EnviroEngine stands for continuous and systematic refinement of the means and solutions for running marine engines at maximum efficiency while eliminating visible smoke, and minimizing the exhaust emissions of carbon dioxide, sulphur and nitrogen oxides formed in the combustion process.



Nitrogen 76%, oxygen 13%, carbon dioxide 5% and water 5% = about 99.5%. Other emissions: nitrogen oxides, carbon monoxide, hydrocarbons, particulates.

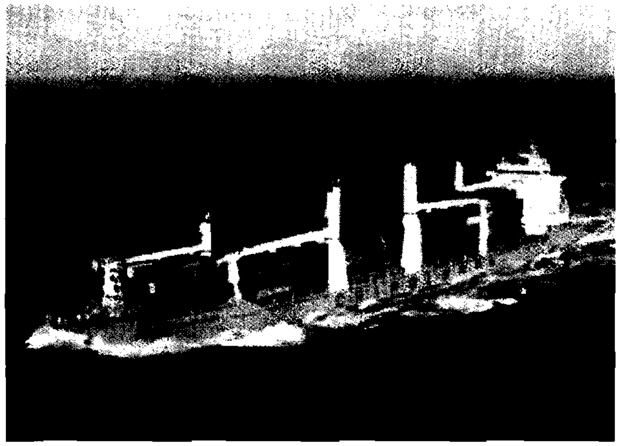


NO_X emissions compliance of Wärtsilä engines.

The Queen Mary 2, with four Wärtsilä 16V46 common rail engines, is not only the world's largest cruise ship but also the first passenger liner to have been built for many years.

The common rail system – The Smokeless Engine

Most harbours in the world are located close to densely populated areas, and the demand for no visible smoke under any circumstances has become increasingly important in recent years. State-of-the-art common rail injection technology now makes it possible to provide smokeless engines. Wärtsilä has the widest range of products available with common rail technology for heavy fuel operation.



Wladyslaw Orkan, multi-purpose container carrier with a Sulzer RT-flex60C engine.

Technology for 4-stroke common rail engines

The design of common rail technology on 4-stroke engines consists of fuel pumps, which feed pressurized fuel oil to accumulators connected to electronically controlled fuel injectors in two cylinders. The accumulators are connected with piping, which is called the common rail. The fuel pumps are driven by the camshaft of the engine. Since the timing of fuel pumping is not connected to the timing of injection, one revolution of the camshaft can include two fuel pumping cycles. This means that fewer pumps can be used than in conventional systems since one pump is enough to feed fuel into two cylinders. All functions are controlled by an integral control system on the engine.

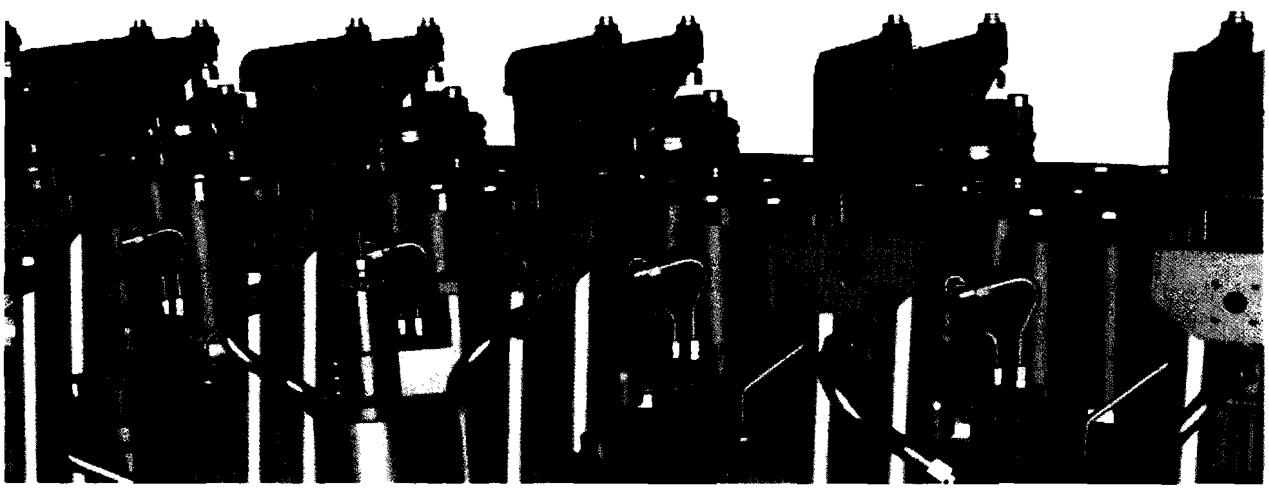
The common rail system design is optimized for new engines but it can also be retrofitted to existing engines.

Common rail is available for the WÄRTSILÄ® 32, Wärtsilä 38 and Wärtsilä 46 engines and is being continuously developed for additional Wärtsilä engines.

Technology for 2-stroke Sulzer RT-flex engines

The RT-flex engine is basically a standard SULZER® RTA low-speed engine from which the camshaft and its gear drive, the complete fuel injection pump units and the related mechanical control gear have been removed. These parts are replaced by four principal elements: the rail unit along the side of the cylinders, the supply unit on the side of the engine, the filter unit for servo oil, and the integrated electronic control system. The common rail is a pipe running the length of the engine just below the cylinder cover level and is fed with heated fuel oil at a pressure up to 1000 bar. Fuel is delivered from the common rail through a separate injection control unit for each engine cylinder to standard fuel injection valves. The control units regulate the timing of fuel injection, control the volume of fuel injected and set the shape of the injection pattern.

Common rail is available in the Sulzer RT-flex50, RT-flex58T, RT-flex60C, RT-flex84T, RT-flex96C and is being continuously developed for additional Sulzer engines.



Design of common rail for 4-stroke engines.

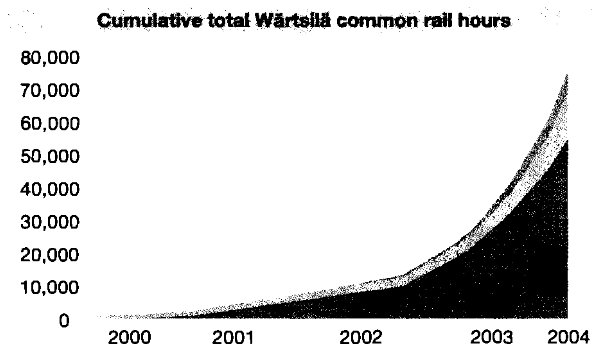
Benefits of common rail

Smokeless operation is demonstrated on all speeds and loads. Superior combustion is achieved by keeping the fuel injection pressure at the optimum level right across the engine speed range.

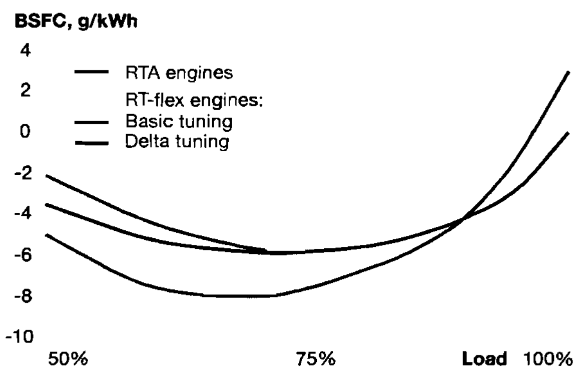
Lower, stable running speeds are available with common rail. This is especially important with 2-stroke engines, which are usually connected to fixed pitch propellers. Speeds down to about 10 rpm for the engines are possible.

Reduced fuel consumption at part load is seen when compared with the existing engines. High injection pressures enable perfect atomization and thus also high efficiency.

Operational experience



Experience of 4-stroke common rail engines.



New Delta tuning gives a lower BSFC curve for the RT-flex engine, compared with the original BSFC curves of the Sulzer RTA and RT-flex engines. All curves shown are for engines complying with the IMO NO_X regulation.

Benefits of common rail

- Smokeless operation on all speeds and loads
- Superior combustion achieved by keeping the fuel injection pressure at the optimum level
- Lower and stable running speeds
- Reduced fuel consumption at part load

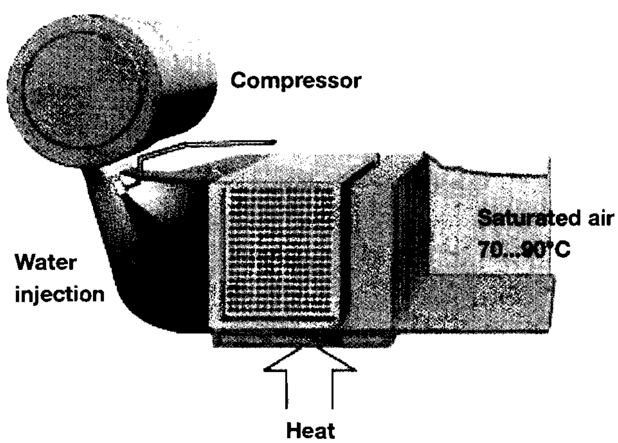
Humidification technologies

Water can be used effectively to limit NO_X formation by reducing temperature peaks during the combustion process.

CASS

The newest NO_X reduction technology developed by Wärtsilä is called CASS – Combustion Air Saturation System. The principle of CASS technology is to introduce pressurized water into the combustion process to reduce NO_X formation. The pressurized water is added to the intake air after the turbocharger compressor. Due to the high temperature of the compressed air, the water evaporates immediately and enters the cylinders as steam, thus lowering the combustion temperatures and the formation of NO_X.

CASS technology has so far been developed for the Wärtsilä 20, 32 and 46 engine types, and the first pilot installation was commissioned in 2003. The anticipated NO_X reduction is up to 50%, and the water consumption is expected to be about two times the fuel oil consumption.



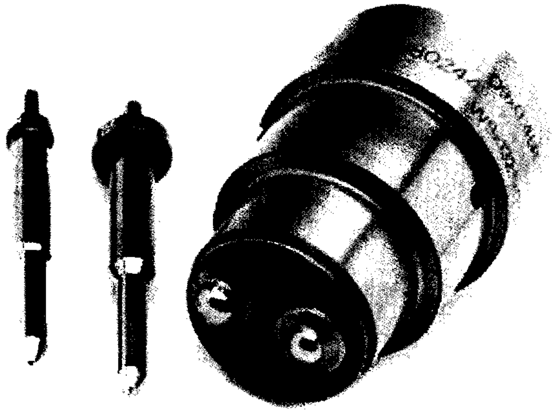
Working principle of the Cass system.

Direct Water Injection

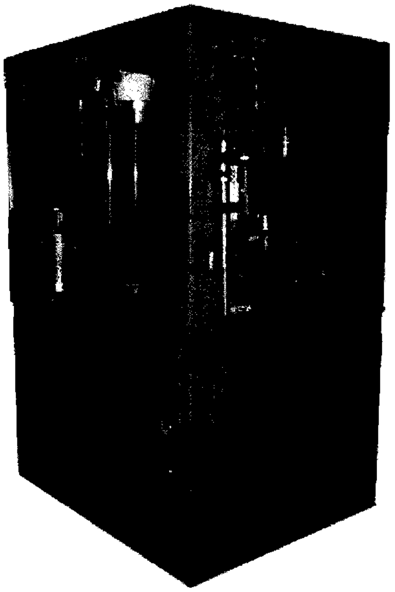
The Direct Water Injection technique reduces NO_X emissions typically by 50-60 % without adversely affecting power output. Built-in safety features enable immediate water shut-off in the event of excessive water flow or water leakage. The water system is completely separate from the fuel system: if water shut-off should prove necessary, engine operation is not affected. The key is the DWI valve through which the water and fuel are injected, typically in a water-to-fuel ratio of 0.4-0.7.

M/S Mistral delivered to Godby Shipping in January 1999 – one of the first of seven forest product carriers equipped with Direct Water Injection.

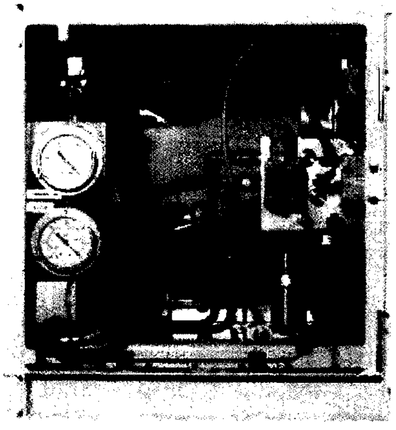
The best environmental performance is achieved by combining the use of DWI with low-sulphur fuel. DWI technology is not recommended with high-sulphur fuels (over 3%).



The combined nozzle for direct water injection.



DWI units for pressurizing water.



The benefits of Direct Water Injection

- NO_x emissions are reduced by 50 - 60 %.
- NO_x when running on marine diesel oil (MDO) typically 4-6 g/kWh; in HFO operation typically 5-7 g/kWh.
- The engine can also be operated without water injection if required.
- The engine can be transferred to "non-water" operational mode at any load.
- In alarm situations transfer to "non-water" mode is automatic and instant.
- Space requirements for the equipment are minimal and therefore the system can be installed in all installations.
- Investment and operational costs are low.
- Ratio of Injected water to injected fuel typically 0.4 - 0.7.
- Can be installed while the ship is in operation.

Compact Selective Catalytic Reduction

The Selective Catalytic Reduction (SCR) process reduces NO_X emissions to harmless substances normally found in the air that we breathe.

SCR is currently the most efficient method of NO_X reduction. A reducing agent, such as an aqueous solution of urea, is injected into the exhaust gas at a temperature of 290-450 °C. The urea in the exhaust gas decays into ammonia, which is then put through a catalysing process that converts the NO_X into harmless nitrogen and water. The SCR method reduces NO_X emissions by 85-95%. Hence, it is easy to reach a NO_X level of 2 g/kWh or lower, which complies with the most stringent levels at sea.

SCR technology

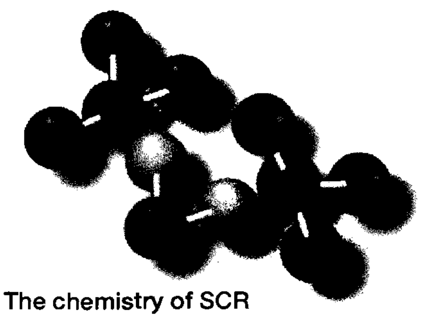
Compact SCR is a combined silencer and SCR unit – hardly any bigger than an ordinary silencer. A typical SCR plant consists of a reactor, which contains several catalyst layers, a dosing and storage system for the reagent, and a control system. The SCR reactor is a square steel container large enough to house the layers of catalytic elements.

The parameter for controlling the amount of urea injected is the engine load. To achieve more accurate control, the injection can be linked to feedback from a NO_X measuring device after the catalyst. The rate of NO_X reduction depends on the amount of urea injected, which can be expressed as the ratio of NH_3 to NO_X. The reduction rate can also be increased by increasing the catalyst volume.

If an exhaust gas boiler is specified, this should be installed after the SCR since the SCR requires a relatively high operating temperature.

The lifetime of the catalyst elements is typically 3-5 years for liquid fuels and slightly longer if the engine is operating on gas. The main running costs of the catalyst come from urea consumption and replacement of the catalyst layers. The urea consumption is about 15 g/kWh of 40 %-wt urea.

The size of the urea tank depends on the size of the engine, the load profile and how often the ship will be entering harbours where urea is available.



The chemistry of SCR

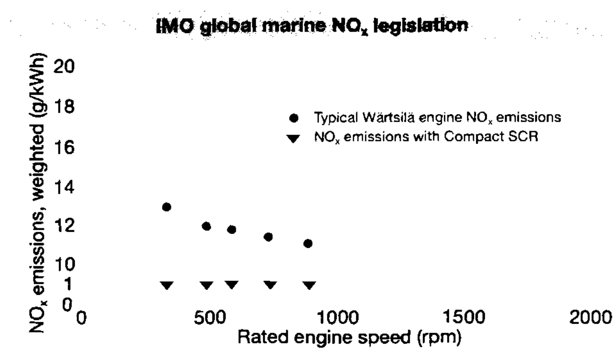
The reducing agent is urea (a 40 %-wt solution), which is a harmless substance used in the agricultural sector. The urea solution is injected into the exhaust gas directly after the turbocharger. Urea decays immediately to ammonium and carbon dioxide according to the following formula:

$(NH_2)_2CO + H_2O + \text{heat} \rightarrow 2\ NH_3 + CO_2$

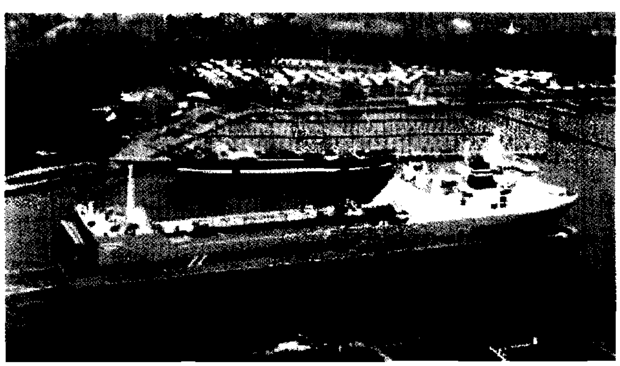
The mixture is passed through the catalyst, where NO_X is converted to nitrogen and water:

$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$

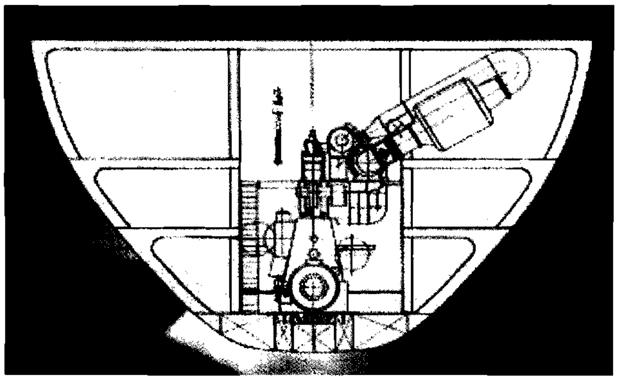
$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$



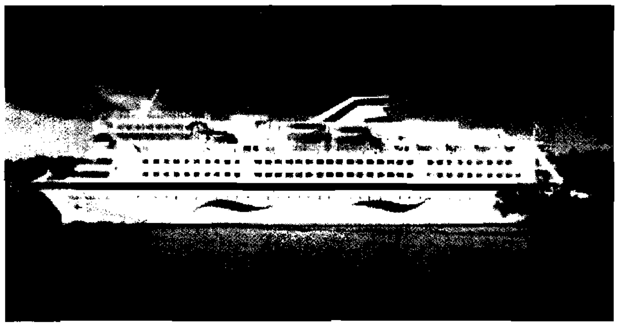
The standard Wärtsilä engines today fulfil IMO regulations.



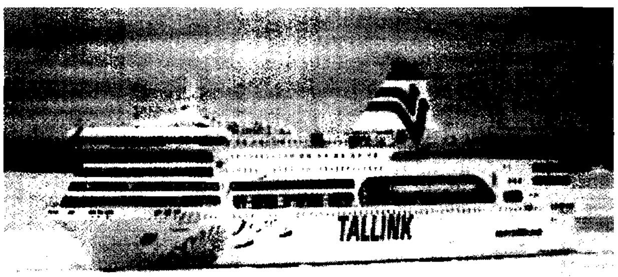
The Ro-Ro paper products carrier Spaarneborg and her two sisters are each powered by a Sulzer 7RTA52U main engine and two Wärtsilä 6L20 auxiliary engines. All engines are equipped with SCR systems to reduce NO_X emissions to the minimum.



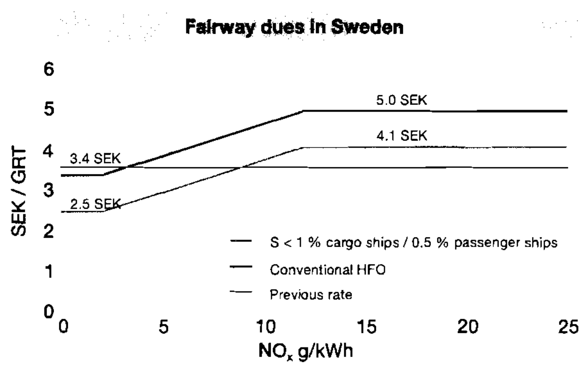
Principal installation of a catalyst unit in a low-speed engine vessel. This is an ideal arrangement with respect to gas flow.
Other arrangements can be tailored to suit the ship design. The first ships to have Sulzer RTA engines with SCR units are three Ro-Ro vessels with seven RTA52U engines. These entered service in November 1999.



The Birka Princess, powered by four 12V32 main engines, two 6R32 and one 4R32 auxiliary engine, is equipped with Compact SCR units on all seven engines.

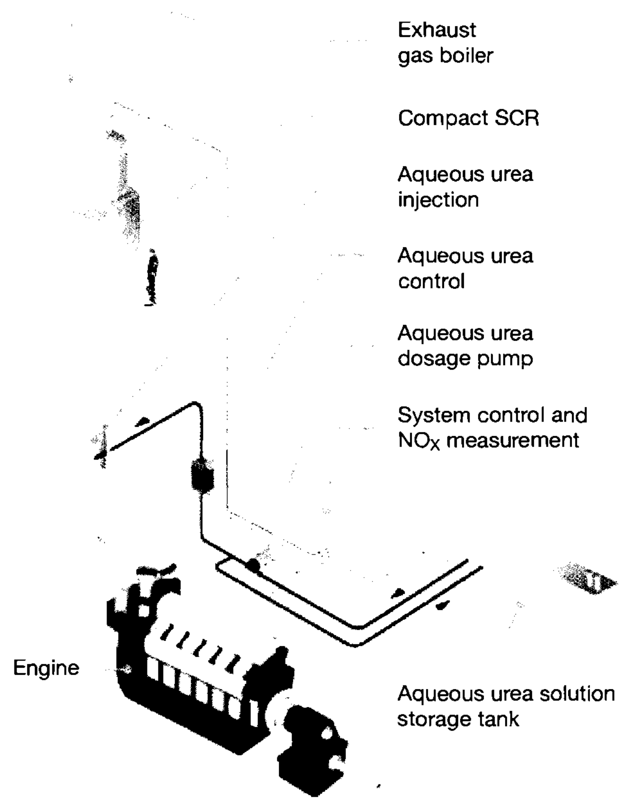


Tallink Victoria. Propulsion by four diesel engines totalling 26,240 kW. The catalytic reduction units installed for better control of exhaust emissions make the vessel most environmentally friendly.



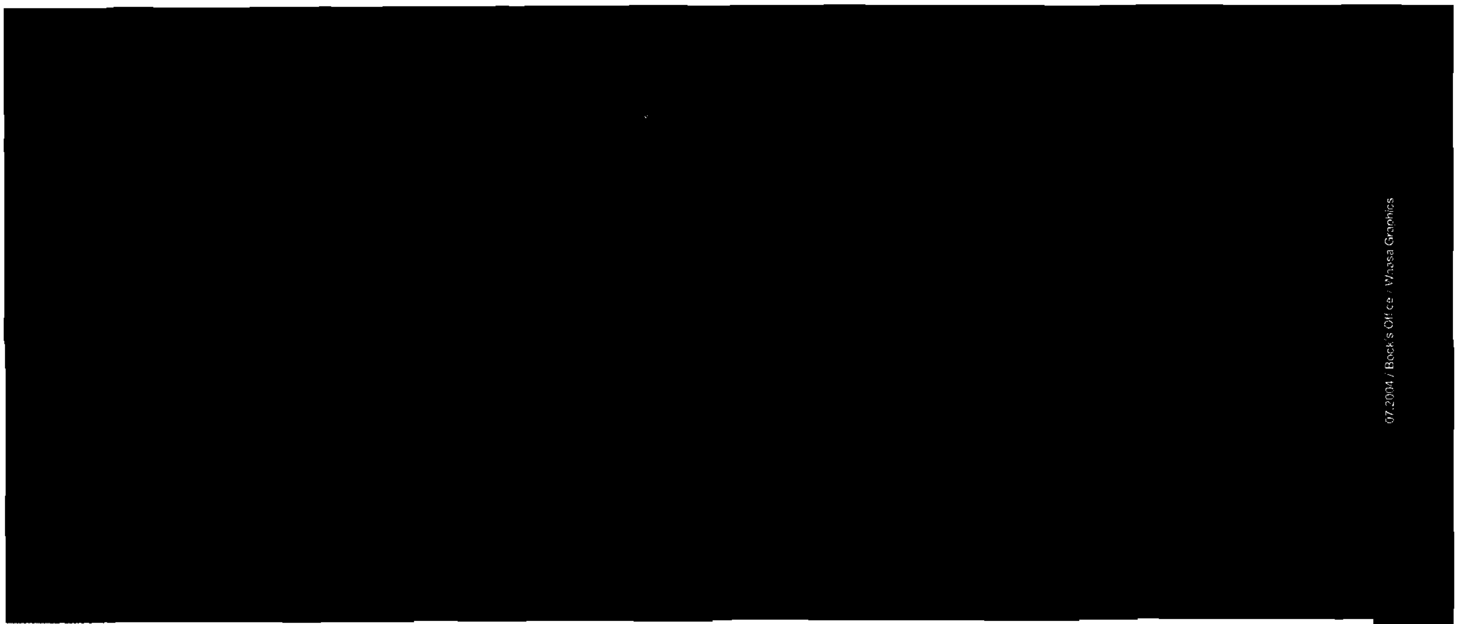
Sweden has established its own system of differentiated fairway dues. This requires that vessels with higher NO_X emissions pay higher fees than environmentally-friendly ships of similar size.

Compact SCR technology is available for all engines in the Wärtsilä portfolio. Wärtsilä today has more than 190 SCR units for medium-speed marine engine and power plant installations either in operation or on order.



Compact SCR by Wärtsilä

- Combined silencer and SCR unit tailored for Wärtsilä engines
- Modular design enabling SCR retrofit
- Minimized size
- NO_X reduction 85-95 %
- Sound attenuation 25-35 dB(A)



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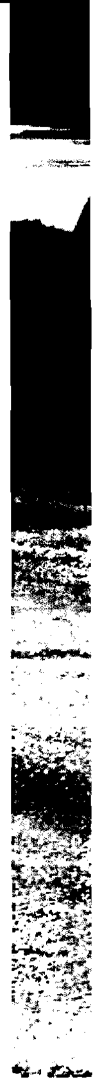

Wärtsilä is The Ship Power Supplier for builders, owners and operators of vessels and offshore installations. We are the only company with a global service network to take complete care of customers' ship machinery at every lifecycle stage.

Wärtsilä is a leading provider of power plants, operation and lifetime care services in decentralized power generation.

The Wärtsilä Group includes Imatra Steel, which specializes in special engineering steels.

For more information visit www.wartsila.com

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Fax: +358 10 709 5700

WÄRTSILÄ

Table FSRU 9: SCV Controlled Average Emissions Summary

SIC	1321		
PROCESS EQPT DESCRIPTION	Submerged Combustion Vaporizer, Selas Sub-X, 120-180 ton LNG/hr, Low NO_X Burner		
FUEL TYPE/PROCESS INFO	Scarborough LNG, 99.7% methane, 1 ppmv S		
TOTAL YEARLY PROCESS RATE	3999.206		
HOURLY PROCESS RATE	0.456530		
PROCESS UNITS	PT074	Million Cubic Feet Burned	
HIGHER HEATING VALUE	1007.6	mmBTU/mmcf	
OPERATING SCHEDULE	8760	hrs/yr	
NUMBER OF DEVICES	4.00	Average	
UNIT RATING	115.000	mmBTU/hr	
HEAT INPUT	460.00	mmBTU/hr	
DRY Fd	8710	dscf/mmBTU	USEPA Method 19
EXHAUST FLOW	4.68	mmdscf/hr	

EMITTENT NAME	EMITTENT PPM	CORR FACTOR	CTL EF LBS/UNIT	ACTUAL LBS/YR	ACTUAL TONS/YR	ACTUAL LBS/HR	RATE lb/mmBTU
Nitrogen Oxides (as NO_2)	5.0	1.0000	6.117	24,463	12.23	2.79	0.0061
Reactive Hydrocarbons (ROC) as CH_4	4.1	1.0000	1.745	6,977	3.49	0.80	0.0017
Carbon Monoxide (CO)	100.0	1.0000	74.466	297,805	148.90	34.00	0.0739
Sulfur Dioxide (SO_2)	0.10	1.0000	0.166	664	0.33	0.08	0.0002
Particulates (as PM_{10}) (grains/dscf)	0.0013	1.0000	1.900	7,598	3.80	0.87	0.0019
Carbon Dioxide (CO_2)	9.2%	1.0000	107656.700	430,541,325	215270.66	49148.55	106.8447
Ammonia Slip (NH_3)							

Emission Factors @ 3% oxygen

NO_X = 20 ppmv (Selas Specification)
ROC = 4.1 ppmv (Costain Report)
CO = 100 ppmv (Selas Specification)
PM_{10} = 1.9 lb/mmcf (AP-42 Table 1.4-2, non-condensible filterable fraction, condensibles remain in 70 F water solution)
CO_2 = 9.2% (Selas Specification, 6.6% @ 8% oxygen)

Device Notes:

FSRU throughput 800 mmcf/day, 365 days/yr, 292 mmmcf/yr total
SCV sendout rate =200 mmscf/day (guarantee)

Table FSRU 9: SCV Controlled Average Emissions Summary

Throughput, mmcf/day	800	design
SCV Sendout, mmcf/day each	200	guarantee
Equivalent SCVs Operating	4.00	average

HAP NAME	UNCTL EF lb/mmcf	CORR FACTOR	CTL EF LBS/UNIT	ACTUAL LBS/YR	ACTUAL TONS/YR	ACTUAL LBS/HR
Acetaldehyde	3.10E-03	1.00	3.10E-03	12.4	0.006	0.001
Acrolein	2.70E-03	1.00	2.70E-03	10.8	0.005	0.001
Benzene	2.10E-03	1.00	2.10E-03	8.4	0.004	0.001
Butadiene -1,3		1.00	0.00E+00	-	0.000	0.000
Ethyl Benzene	6.90E-03	1.00	6.90E-03	27.6	0.014	0.003
Formaldehyde	7.50E-02	1.00	7.50E-02	299.9	0.150	0.034
Hexane	4.60E-03	1.00	4.60E-03	18.4	0.009	0.002
Naphthalene	6.10E-04	1.00	6.10E-04	2.4	0.001	0.000
PAHs	8.82E-05	1.00	8.82E-05	0.4	0.000	0.000
Propylene	5.30E-01	1.00	5.30E-01	2,119.6	1.060	0.242
Toluene	3.40E-03	1.00	3.40E-03	13.6	0.007	0.002
Xylenes	1.97E-02	1.00	1.97E-02	78.8	0.039	0.009

HAP Emission Factors: AP-42 Table 1.4-3 (benzene, formaldehyde, napthalene, PAHs, toluene)
VCAPCD 8/25/95 all others

Exhaust Gas (Selas)	**Vol %**	**MW**	**MW**	**Wt %**	**Cp**	**Cp**
Carbon Dioxide	0.066	44.010	2.90	0.100	0.1991	0.0199
Nitrogen	0.815	28.013	22.83	0.787	0.2482	0.1954
Oxygen	0.080	31.999	2.56	0.088	0.2188	0.0193
Water vapor	0.039	18.015	0.70	0.024	0.4446	0.0108
TOTAL	**1.000**		**29.00**	**1.000**		**0.2454**
			lb/mole			**BTU/lb-F**

Table FSRU 9: SCV Controlled Average Emissions Summary

Exhaust flowrate	28,605	scfm
Exhaust flowrate	2,186	lb/min
TOTAL flowrate (4 running)	524,573	lb/hr
Exhaust temperature, F	70	lower
SCR Inlet, F	650	upper
Delta T , F	580	max
Specific Heat, BTU/lb-F	0.2454	
Heat Input, mmBTU/hr	74.68	
Recuperative heat revovery	85%	
Net heat, mmBTU/hr	**11**	
Fuel gas, mmcf/yr	**96**	
Percent Increase	2.4%	

Duct Burner GHG emissions	lb/mmcf	ton/yr
CO	84	4.0
CO_2	120,000	5,760
PM	7.6	0.4
ROC	5.5	0.3
SO_X	0.166	0.0

AKER KVÆRNER PROCESS CALCULATION	PREP. BY	BRM			
	CHKD. BY				
	APPROVED				
	DATE	12/12/2006			
	ISSUE				

CLIENT:BHP	PROJECT No.:H0690900	ITEM No.General Calculations
LOCATION:Offshore, CA	PFD No.:	EFD No.:
PLANT:Cabrillo Port	PROCESS AREA:	
SERVICE:	EQUIPMENT NAME:	

Calculate Stack Temperature assuming no oxidation in CO Oxidation bed

Assume ignition in the flammable region and reaction proceeds until all oxygen in exhaust gas is reacted

Exhaust Gas

Flow	113000	lb/hr
Temperature	600	F
Pressure	15	psia

Composition	Mol %
CO_2	8.50
H_2O	3.44
O_2	5.08
N_2	82.01
Ar	0.98

Hydrocarbon leak is methane

The system is modeled in Hysys with the following results

	Leak lb/hr	Stack Temp °F (6)	
	0	600	
	1000	586	
	2000	573	
	3000	561	
(1) (2)	3258	558	Reaches LFL methane
	4000	1516	
	5000	1482	
	6000	1449	
(3)	7000	1418	
	8000	1389	
	9000	1361	
	10000	1335	
(4)	10918	1311	Exceeds UFL methane
	15000	446	
	20000	410	
	25000	380	
	30000	353	
	40000	309	
	60000	244	
	80000	199	
	100000	165	
(5)	135000	123	

(1) As shown in the attached curve, the maximum temperature would occur if the leak is sufficient to reach the LFL and ignition occurs

(2) At this point there is sufficient methane to consume all of the oxygen in the exhaust

(3) Ignition could occur throughout the flammable region

(4) As shown in the attached curve, ignition cannot occur if the leak is sufficient to exceed the UFL of methane

(5) Flow through a break in a 1" tube was also calculated. This value is approximately 135,000 lb/hr.

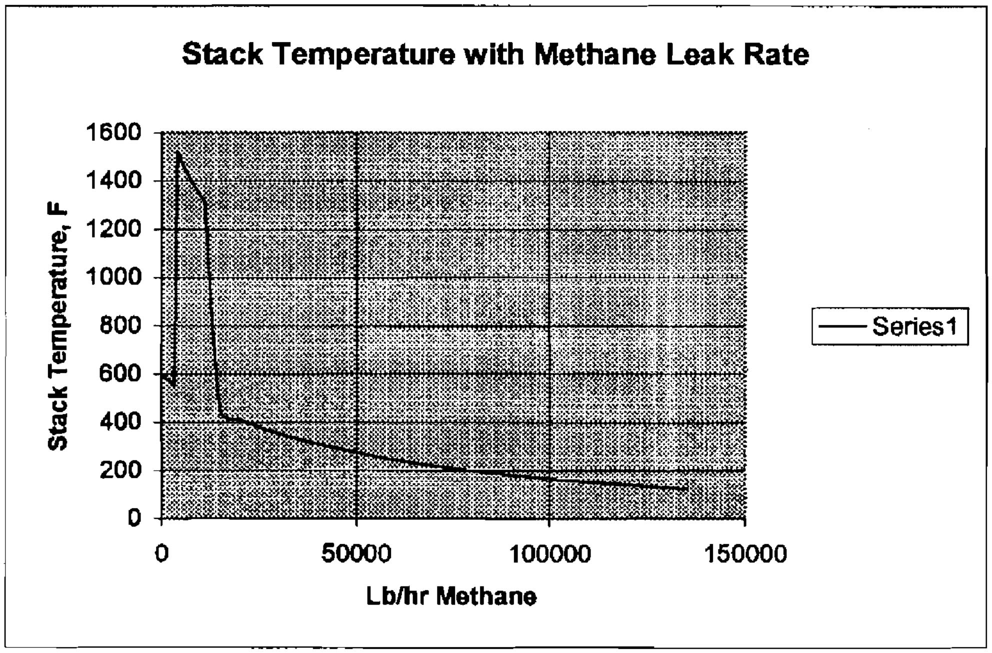
(6) Assuming no action taken by control system

AKER KVÆRNER

PROCESS CALCULATION

PREP. BY				
CHKD. BY				
APPROVED				
DATE				
ISSUE				

CLIENT:BHP	PROJECT No.:H0690900	ITEM No.General Calculations
LOCATION:Offshore, CA	PFD No.:	EFD No.:
PLANT:Cabrillo Port	PROCESS AREA:	
SERVICE:	EQUIPMENT NAME:	



AKER KVÆRNER™

TUBE RUPTURE (SINGLE-PHASE) FLOW CALCULATION

Project No.:	H0690900	**Project Name:**	Cabrillo Port	**Date:**	10-Nov-06
Client:	BHP	**Location:**	Offshore	**By:**	BRM
Equip. No.:	SCV	**Equip. Name:**	SCV	**Checked:**	

	Item	Value	Unit	Symbol	Crane Manual Reference
	1. Enter Outer Diameter of Tube	1.000	in		
	2. Enter Thickness of Tube	0.083	in		
	Calculated Inner Diameter of Tube	0.834	in	d_1	
	Friction Factor of Tube	0.023			(A-26)
	3. Enter Length of Tube	20.0	ft		
	4. Enter Molecular Weight	16.04			
	5. Enter Specific Heat Ratio	1.58		k or C_p/C_v	
	6. Enter Initial Pressure	1500.0	psig	P_1	
	Calculated P_1'	1514.7	psia	P_1'	
	7. Enter Initial Density	24.210	lb/ft^3		
	8. Enter Pressure at Exit	1.0	psig	P_2	
	Calculated $(P_1-P_2)/P_1'$	0.990		$(\Delta P)/P_1'$	
Flow Through Tube	Inlet Resistance Coefficient	0.5		K_{in}	(A-29)
	Outlet Resistance Coefficient	1.0		K_{out}	(A-29)
	Tube Resistance Coefficient	6.62		K_{tube}	(3-4)
	Total Resistance Coefficient	8.12		K_{total}	
	9. Enter Critical $(P_1-P_c)/P_1'$ per A-22 for K_{total}	0.560		$(\Delta P)/P_1'$	(A-22)
	Calculated Critical Pressure	651.8	psig	P_c	
	10. Enter Critical Expansion Factor per K_{total}	0.720			(A-22)
	Type of flow (sonic / subsonic)?	SONIC			
	CONDITIONS AT RUPTURE:				
	$(P_1-P_2)/P_1'$	0.560		$(\Delta P)/P_1'$	
	Exit Pressure	651.8	psig	P_2	
	11. Enter Temperature	-200.0	°F		
	12. Enter Compressibility Factor	0.360			
	Calculated Density	10.644	lb/ft^3	Not used in the calc	
	Expansion Factor	0.720		Y	(A-22)
	CALCULATED FLOWRATE	47629	lb/hr	$W=1891*Y*d^2*((P_1-P_2)*\rho_1/K)^{0.5}$	(4-13)
Flow Through Orifice	13. Flow Coefficient	0.65		C	(Use 0.65 per Crane A-19)
	14. Enter Ratio of Orifice Diam. to Pipe Diam.	0.2		β or d_1/d_2	(0.2 for max. flow)
	15. Enter Critical Pressure Ratio	0.440		r_c or P'_2/P'_1	(A-21)
	Calculated Critical Pressure	651.6	psig	P_c	
	Type of flow (sonic / subsonic)?	SONIC			
	CONDITIONS AT RUPTURE:				
	Exit Pressure	651.8	psig	P_2	
	$(P_1-P_2)/P_1'$	0.560		$(\Delta P)/P_1'$	
	Temperature	-200.00	°F		
	Compressibility Factor	0.360			
	Calculated Density	10.644	lb/ft^3	Not used in the calc	
	16. Enter Expansion Factor	0.72			(A-21)
	CALCULATED FLOWRATE	88211	lb/hr	$W=1891*Y*d^2*C*((P_1-P_2)*\rho_1)^{0.5}$	(3-24)
	TOTAL FLOWRATE AT RUPTURE	135840	lb/hr		

NOTES:

P:\H0690900\08.0 ENGINEERING\08.01 Process Engineering\08.01.08 Process Studies\Appendix D\[Tube Rupture.xls]Exch TubeRupture

COST EFFECTIVENESS CALCULATIONS	PROJECT TITLE: Cabrillo Port	PAGE: 1	OF: 3	SHEET: 1
	SUBJECT: NOx CONTROL COST ANALYSIS	DATE: December 1, 2006		

TABLE 1A*

CAPITAL COSTS FOR
NOx Reduction Catalyst

(BASED ON EQUIPMENT COST OF $12,000,000--2006)

Cost Category		Cost Factor			Cost ($)
DIRECT COSTS					
1.	Purchased Equipment:				
	A. Primary and Auxiliary Equipment Cost				12,000,000
	B. Instrumentation and Controls	0.10	X	12,000,000	1,200,000
	C. Sales Tax	0.07	X	12,000,000	870,000
	D. Freight	0.05	X	12,000,000	600,000
	Total Purchased Equipment Costs:				**14,670,000**
2.	Installation Costs:				
	A. Foundations and supports	0.08	X	14,670,000	1,173,600
	B. Erection and handling	0.14	X	14,670,000	2,053,800
	C. Electrical	0.04	X	14,670,000	586,800
	D. Piping	0.02	X	14,670,000	293,400
	E. Insulation	0.01	X	14,670,000	146,700
	F. Painting	0.01	X	14,670,000	146,700
	G. FSRU Extension	1.00	X	30,000,000	30,000,000
	Total Installation Costs:				**34,401,000**
TOTAL DIRECT COSTS:					49,071,000
INDIRECT COSTS					
1.	Engineering and Supervision	0.10	X	14,670,000	1,467,000
2.	Construction and Field Expenses	0.05	X	14,670,000	733,500
3.	Construction Fee	0.10	X	14,670,000	1,467,000
4.	Start-Up	0.01	X	14,670,000	146,700
5.	Performance Test	0.01	X	14,670,000	146,700
6.	Contingency	0.05	X	14,670,000	733,500
TOTAL INDIRECT COSTS:					**4,694,400**
TOTAL CAPITAL COST:					53,765,400

* The cost multipliers used in this table are derived from past experience and EPA values used for regulatory purposes. They are used herein for the purpose of comparing costs among options. Actual costs based on project and site uniquenesses may vary from these table values. Multipliers for marine installations would be expected to be significantly higher.

COST EFFECTIVENESS CALCULATIONS	PROJECT TITLE: Cabrillo Port	PAGE: 2	OF: 3	SHEET: 1
	SUBJECT: NOx CONTROL COST ANALYSIS	DATE: December 1, 2006		

TABLE 1B*

OPERATING COSTS FOR NOx Reduction Catalyst

(BASED ON EQUIPMENT COST OF $12,000,000--2006)

	Cost Category				Cost Factor		Cost ($)
DIRECT COSTS							
1	Operating Labor	116.44	$/hr	X	2,920	hrs/yr	$340,005
2	Supervisory Labor		0.15	X	340,005	$/yr	$51,001
3	Maintenance Labor	116.44	$/hr	X	2,920	hrs/yr	$340,005
							$731,010
4	Replacement Parts						
	A. Catalyst (8 beds/yr)						$2,000,000
	B. Other (100% of maintenance labor)						$340,005
5	B. Utilities						$0
6	Fuel Penalty $ 6 /MMBtu X	29.29	MMBtu/hr X		8760	hr/yr X 1	$1,539,482
	TOTAL DIRECT COSTS:						**$4,610,497**
INDIRECT COSTS							
1	Overhead		0.60	X	731,010		$438,606
2	Property Tax		0.01	X	53,765,400		$537,654
3	Insurance		0.01	X	53,765,400		$537,654
4	Administration		0.02	X	53,765,400		$1,075,308
5	Capital Recovery 7.00% int.	10 yrs	0.14	X	53,765,400		$7,654,983
	TOTAL INDIRECT COSTS:						**$10,244,206**
TOTAL OPERATING COST (ANNUALIZED):							$14,854,703

* The cost multipliers used in this table are derived from past experience and EPA values used for regulatory purposes. They are used herein for the purpose of comparing costs among options. Actual costs based on project and site uniquenesses may vary from these table values.

COST EFFECTIVENESS CALCULATIONS	PROJECT TITLE: Cabrillo Port	PAGE: 3	OF: 3	SHEET: 1
	SUBJECT: NOx CONTROL COST ANALYSIS	DATE: December 1, 2006		

TABLE 1C

INCREMENTAL COST EFFECTIVENESS OF NOx Reduction Catalyst

(BASED ON EQUIPMENT COST OF $12,000,000–2006)

1. ANNUAL COST

COSTS	AMOUNT
Direct Operating	$4,610,497
Indirect Operating	$10,244,206
TOTAL ANNUALIZED COST	$14,854,703

2. NOx EMISSIONS

Controls	Emission Rate	NOx Emissions (ton/yr)	Tons Removed (ton/yr)
Baseline Unit	40 ppmv	97.85	
SCR Controlled Unit	5 ppmv	12.23	85.62
Lean Premix Unit	20 ppmv	48.93	
SCR Controlled Unit	5 ppmv	12.23	36.70

3. COST OF CONTROL PER TON OF POLLUTANT REMOVED

Control Scenario	Annual Costs	Tons of NOx Controlled per Year	Cost per Ton	
Oxidation Catalyst	$14,854,703	85.62	$173,496	Average
	$14,854,703	36.70	$404,760	Incremental

SCV+SCR Hull Modification Cost

YEAR	2003	2010	2003	2012	
LOCATION	Korea		Japan		
Comments	*Base Case*	*Adjusted for 2010*	*Korea Labour +13%*	*Adjusted for 2010*	UNIT
Original BASE CASE Data					
Length of FSRU (LPP)	292.8	292.8	292.8	292.8	m
STEEL WEIGHT	40,334.6	40,334.6	40,334.6	40,334.6	tonne
Steel weight per unit length	137.8	137.8	137.8	137.8	tonne/m
Modfication to Base Case Data					
Length Increase	30.0	30.0	30.0	30.0	m
Steel weight Increase	4,132.6	4,132.6	4,132.6	4,132.6	tonne
Cost Components					
Material Cost per tonne of steel	1,625.9	2,357.5	1,625.9	2,357.5	USD/tonne (includes all materials)
Material cost other than steel per tonne	542.0	785.8	542.0	785.8	USD/tonne
Total Material Cost/tonne	2,167.8	3,143.4	2,167.8	3,143.4	USD/tonne
Manhour	200.0	200.0	200.0	200.0	h/tonne
Manhour cost	15.0	21.0	17.0	23.7	USD
Labour Cost/tonne of steel	3,000.0	4,200.0	3,390.0	4,746.0	USD/tonne
Total per tonne of steel	5,167.8	7,343.4	5,557.8	7,889.4	USD/tonne
Additional CAPEX due to Modification					
CAPEX additional length	21,356,812.0	30,347,480.9	22,968,542.9	32,603,904.2	USD

Table FSRU 9: SCV Controlled Average Emissions Summary

SIC	1321		
PROCESS EQPT DESCRIPTION	Submerged Combustion Vaporizer, Selas Sub-X, 120-180 ton LNG/hr, Low NO_X Burner		
FUEL TYPE/PROCESS INFO	Scarborough LNG, 99.7% methane, 1 ppmv S		
TOTAL YEARLY PROCESS RATE	3999.206		
HOURLY PROCESS RATE	0.456530		
PROCESS UNITS	PT074	Million Cubic Feet Burned	
HIGHER HEATING VALUE	1007.6	mmBTU/mmcf	
OPERATING SCHEDULE	8760	hrs/yr	
NUMBER OF DEVICES	4.00	Average	
UNIT RATING	115.000	mmBTU/hr	
HEAT INPUT	460.00	mmBTU/hr	
DRY Fd	8710	dscf/mmBTU	USEPA Method 19
EXHAUST FLOW	4.68	mmdscf/hr	

EMITTENT NAME	EMITTENT PPM	CORR FACTOR	CTL EF LBS/UNIT	ACTUAL LBS/YR	ACTUAL TONS/YR	ACTUAL LBS/HR	RATE lb/mmBTU
Nitrogen Oxides (as NO_2)	40.0	1.0000	48.935	195,701	97.85	22.34	0.0486
Reactive Hydrocarbons (ROC) as CH_4	4.1	1.0000	1.745	6,977	3.49	0.80	0.0017
Carbon Monoxide (CO)	100.0	1.0000	74.466	297,805	148.90	34.00	0.0739
Sulfur Dioxide (SO_2)	0.10	1.0000	0.166	664	0.33	0.08	0.0002
Particulates (as PM_{10}) (grains/dscf)	0.0013	1.0000	1.900	7,598	3.80	0.87	0.0019
Carbon Dioxide (CO_2)	9.2%	1.0000	107656.700	430,541,325	215270.66	49148.55	106.8447
Ammonia Slip (NH_3)							

Emission Factors @ 3% oxygen

NO_X = 20 ppmv (Selas Specification)

ROC = 4.1 ppmv (Costain Report)

CO = 100 ppmv (Selas Specification)

PM_{10} = 1.9 lb/mmcf (AP-42 Table 1.4-2, non-condensible filterable fraction, condensibles remain in 70 F water solution)

CO_2 = 9.2% (Selas Specification, 6.6% @ 8% oxygen)

Device Notes:

FSRU throughput 800 mmcf/day, 365 days/yr, 292 mmmcf/yr total

SCV sendout rate =200 mmscf/day (guarantee)

Table FSRU 9: SCV Controlled Average Emissions Summary

Throughput, mmcf/day	800	design
SCV Sendout, mmcf/day each	200	guarantee
Equivalent SCVs Operating	4.00	average

HAP NAME	UNCTL EF lb/mmcf	CORR FACTOR	CTL EF LBS/UNIT	ACTUAL LBS/YR	ACTUAL TONS/YR	ACTUAL LBS/HR
Acetaldehyde	3.10E-03	1.00	3.10E-03	12.4	0.006	0.001
Acrolein	2.70E-03	1.00	2.70E-03	10.8	0.005	0.001
Benzene	2.10E-03	1.00	2.10E-03	8.4	0.004	0.001
Butadiene -1,3		1.00	0.00E+00	-	0.000	0.000
Ethyl Benzene	6.90E-03	1.00	6.90E-03	27.6	0.014	0.003
Formaldehyde	7.50E-02	1.00	7.50E-02	299.9	0.150	0.034
Hexane	4.60E-03	1.00	4.60E-03	18.4	0.009	0.002
Naphthalene	6.10E-04	1.00	6.10E-04	2.4	0.001	0.000
PAHs	8.82E-05	1.00	8.82E-05	0.4	0.000	0.000
Propylene	5.30E-01	1.00	5.30E-01	2,119.6	1.060	0.242
Toluene	3.40E-03	1.00	3.40E-03	13.6	0.007	0.002
Xylenes	1.97E-02	1.00	1.97E-02	78.8	0.039	0.009

HAP Emission Factors: AP-42 Table 1.4-3 (benzene, formaldehyde, napthalene, PAHs, toluene)
VCAPCD 8/25/95 all others

Exhaust Gas (Selas)	**Vol %**	**MW**	**MW**	**Wt %**	**Cp**	**Cp**
Carbon Dioxide	0.066	44.010	2.90	0.100	0.1991	0.0199
Nitrogen	0.815	28.013	22.83	0.787	0.2482	0.1954
Oxygen	0.080	31.999	2.56	0.088	0.2188	0.0193
Water vapor	0.039	18.015	0.70	0.024	0.4446	0.0108
TOTAL	**1.000**		**29.00**	**1.000**		**0.2454**
			lb/mole			**BTU/lb-F**

Table FSRU 9: SCV Controlled Average Emissions Summary

Exhaust flowrate	28,605	scfm
Exhaust flowrate	2,186	lb/min
TOTAL flowrate (4 running)	524,573	lb/hr
Exhaust temperature, F	70	lower
SCR Inlet, F	650	upper
Delta T , F	580	max
Specific Heat, BTU/lb-F	0.2454	
Heat Input, mmBTU/hr	74.68	
Recuperative heat revovery	85%	
Net heat, mmBTU/hr	**11**	
Fuel gas, mmcf/yr	**96**	
Percent Increase	2.4%	

Duct Burner GHG emissions	lb/mmcf	ton/yr
CO	84	4.0
CO_2	120,000	5,760
PM	7.6	0.4
ROC	5.5	0.3
SO_X	0.166	0.0

Table FSRU 9: SCV Controlled Average Emissions Summary

SIC	1321		
PROCESS EQPT DESCRIPTION	Submerged Combustion Vaporizer, Selas Sub-X, 120-180 ton LNG/hr, Low NO_X Burner		
FUEL TYPE/PROCESS INFO	Scarborough LNG, 99.7% methane, 1 ppmv S		
TOTAL YEARLY PROCESS RATE	3999.206		
HOURLY PROCESS RATE	0.456530		
PROCESS UNITS	PT074	Million Cubic Feet Burned	
HIGHER HEATING VALUE	1007.6	mmBTU/mmcf	
OPERATING SCHEDULE	8760	hrs/yr	
NUMBER OF DEVICES	4.00	Average	
UNIT RATING	115.000	mmBTU/hr	
HEAT INPUT	460.00	mmBTU/hr	
DRY Fd	8710	dscf/mmBTU	USEPA Method 19
EXHAUST FLOW	4.68	mmdscf/hr	

EMITTENT NAME	EMITTENT PPM	CORR FACTOR	CTL EF LBS/UNIT	ACTUAL LBS/YR	ACTUAL TONS/YR	ACTUAL LBS/HR	RATE lb/mmBTU
Nitrogen Oxides (as NO_2)	20.0	1.0000	24.467	97,850	48.93	11.17	0.0243
Reactive Hydrocarbons (ROC) as CH_4	4.1	1.0000	1.745	6,977	3.49	0.80	0.0017
Carbon Monoxide (CO)	100.0	1.0000	74.466	297,805	148.90	34.00	0.0739
Sulfur Dioxide (SO_2)	0.10	1.0000	0.166	664	0.33	0.08	0.0002
Particulates (as PM_{10}) (grains/dscf)	0.0013	1.0000	1.900	7,598	3.80	0.87	0.0019
Carbon Dioxide (CO_2)	9.2%	1.0000	107656.700	430,541,325	215270.66	49148.55	106.8447
Ammonia Slip (NH_3)							

Emission Factors @ 3% oxygen

NO_X = 20 ppmv (Selas Specification)

ROC = 4.1 ppmv (Costain Report)

CO = 100 ppmv (Selas Specification)

PM_{10} = 1.9 lb/mmcf (AP-42 Table 1.4-2, non-condensible filterable fraction, condensibles remain in 70 F water solution)

CO_2 = 9.2% (Selas Specification, 6.6% @ 8% oxygen)

Device Notes:

FSRU throughput 800 mmcf/day, 365 days/yr, 292 mmmcf/yr total

SCV sendout rate =200 mmscf/day (guarantee)

Table FSRU 9: SCV Controlled Average Emissions Summary

Throughput, mmcf/day	800	design
SCV Sendout, mmcf/day each	200	guarantee
Equivalent SCVs Operating	4.00	average

HAP NAME	UNCTL EF lb/mmcf	CORR FACTOR	CTL EF LBS/UNIT	ACTUAL LBS/YR	ACTUAL TONS/YR	ACTUAL LBS/HR
Acetaldehyde	3.10E-03	1.00	3.10E-03	12.4	0.006	0.001
Acrolein	2.70E-03	1.00	2.70E-03	10.8	0.005	0.001
Benzene	2.10E-03	1.00	2.10E-03	8.4	0.004	0.001
Butadiene -1,3		1.00	0.00E+00	-	0.000	0.000
Ethyl Benzene	6.90E-03	1.00	6.90E-03	27.6	0.014	0.003
Formaldehyde	7.50E-02	1.00	7.50E-02	299.9	0.150	0.034
Hexane	4.60E-03	1.00	4.60E-03	18.4	0.009	0.002
Naphthalene	6.10E-04	1.00	6.10E-04	2.4	0.001	0.000
PAHs	8.82E-05	1.00	8.82E-05	0.4	0.000	0.000
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HAP Emission Factors: AP-42 Table 1.4-3 (benzene, formaldehyde, napthalene, PAHs, toluene)
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TOTAL	**1.000**		**29.00**	**1.000**		**0.2454**
			lb/mole			**BTU/lb-F**

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10/6/06